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# Future Drivers and Trends Affecting Energy Development in Ontario

## THE FUTURE OF ELECTRICITY SUPPLY


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Emerging Energy Trends

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Mowat Energy's *Emerging Energy Trends* is a comprehensive study of how technological and consumer disruptions in the energy sector could affect Ontario and beyond.

This paper is part of a series of background reports informing the final report. Initial funding for this research was in part provided by the Ministry of Energy of Ontario. The final report and all other background reports are available at mowatcentre.ca/emerging-energy-trends.

The Mowat Energy research hub provides independent, evidence-based research and analysis on systemic energy policy issues facing Ontario and Canada. With its strong relationship with the energy sector, Mowat Energy has provided thought leadership to stakeholders, decision-makers and the public to help advance discussions on the challenges that energy is facing in Ontario.

This paper produced by Navigant.

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# EXECUTIVE SUMMARY

Industry stakeholders generally recognise that the long-term solution to meeting demand for electric power will look very different from the conventional system in place today. While the transition to a new paradigm that places a greater emphasis on distributed energy resources creates tremendous opportunities to reduce carbon emissions, it also poses legitimate threats to the existing business model of utilities and centralised power generation asset owners.

## Outlook for Centralised Generation

Centralised power generation (i.e. the larger natural gas, coal, hydroelectric, and nuclear power plants that make up the vast majority of electrical power generation capacity worldwide) is likely to continue to play an important role in the electricity sector. However, the challenge for centralised power is that the companies that currently provide the electricity from large centralised power plants and the transmission infrastructure to get it to customers, are going to (through economics, legislation, and/or regulation) have to evolve to protect the value of these assets in the face of increasing opportunities and improving economics for distributed energy resources. Complicating the issue is that the evolution of the power sector will look different in each jurisdiction depending on the local regulatory, policy, and resource conditions.

Notable developments in the sector and their effect on centralised generation are illustrated in Table 1.

**Table 1. Industry Trends and Impact on Centralised Generation**

| Development | Impact on Centralised Generation |
|---|---|
| Decreasing natural gas fuel costs | Decreasing natural gas fuel costs led by the discovery and extraction of shale gas resources has lowered the cost of centralised natural gas fired generation relative to (i) renewables, and (ii) distributed energy resources more broadly. |
| Coal power plant retirements | Coal power plant retirements, for both policy and economic reasons create an opportunity to rebuild a significant portion of the power system, but at the same time are inciting debate around the future role of centralised versus distributed energy resources. |
| Upgrading of hydroelectric and nuclear power plants | Permitting of large centralised power generation facilities is always challenging. Efficiency improvements and refurbishments to existing power plants have resulted in significant increases in capacity or life extensions, negating the need to undergo a permitting process that could last decades. |
| China's 5-year energy plans | China's massive energy investments have made it the leading source of both renewable and non-renewable power capacity additions, driving dramatic cost reductions for components and improving the cost-effectiveness of a number of centralised and decentralised generation technologies. |
| Climate change and the transition to renewables | Climate change policy is driving new investment in renewable power generation capacity, which reached approximately CAD$ 300 billion (US$ 270) in 2015 and is expected to increase five to seven percent globally each year over the next decade. |
| Need for energy storage | In regions with a higher penetration of large-scale renewables, investments in energy storage are occurring to provide grid services such as regulation, voltage support, and load following. These investments, as well as others in energy storage, are driving dramatic cost reductions that will impact future energy supply decisions. |

*Source: Navigant*

New centralised power generation capacity is expected to be largely made up of nuclear, natural gas, utility-scale solar photovoltaics, utility-scale wind, and utility-scale storage. As utility-scale energy storage costs continue to decline with increased deployment through the 2020s, natural gas power plants may be less competitive compared to renewables plus storage. This trend, and declining reliance on coal in Europe and North America, suggests that fossil fuel generation could decrease significantly from 50 percent of total new installed central generation capacity worldwide to under 15 percent by 2050, as net new capacity additions are driven by resources such as wind, solar, storage, and nuclear (Figure 1-1). These new capacity additions are likely to be a mix of centralised, large-scale, power plants and distributed energy resources.

## Distributed Energy Resources, the Disruptor

Distributed energy resources (DER) are challenging the dominance of centralised power generation and the traditional structure of the electricity sector. According to recent estimates, roughly CAD$ 10.5 to 13.5 billion (USD$14 to $18) of electricity sales revenue is lost annually due to transmission and distribution line losses worldwide. This reality, combined with decreasing technology costs and recent events highlighting the fragility of the centralised electricity network, has generated unprecedented interest in the development of distributed energy resources. Encompassing a broad set of solutions that include systems and technologies designed to operate closer to customers on the electricity grid, the proliferation of DER around the world has begun to have a significant, and at times controversial, impact on the electricity grid and industry.

DER includes technologies with unique characteristics that can act as both generation and/or load control on the grid. Despite different operating characteristics, these technologies all represent new and dynamic resources that are challenging the prevailing business models and operating procedures in the industry. The technologies covered in this report are generally installed behind-the-meter (BTM) at customer facilities and may be owned by customers themselves, third-party vendors, or utilities. While these resources are primarily designed to provide value and benefits for the end users hosting them, their integration into the grid can have significant impacts for utilities and grid operators.

A plethora of technology, policy, economic, and customer considerations serve as drivers, enablers, and barriers for DER adoption. It is not just a technical problem that needs to be solved, but rather a series of enabling technologies, commercial considerations, and regulatory policy that interplay with each other. Sometimes success is a moving target depending on which is advancing faster. Business models and technology will need to be flexible and adaptive to accommodate the changing landscape.

Economics, the ability for end users to reduce their energy expenditures, supported by targeted policies (i.e. financial incentives) is a large driver for DER. Reliability and environmental concerns are secondary but growing influencers. There are also a number of complementary enabling technologies and trends that further encourage DER deployment, such as new business models, advanced metering infrastructure (AMI), and dynamic prices.

The picture is not all rosy for DER growth, as a number of barriers to widespread deployment still exist. Some of these factors are simply the flip-side of the drivers, like cost and policy, while others have to do with the existing energy industry structure and infrastructure.

Looking at the technical aspects of DER, there are advancements and implementation techniques related directly to the resources as well as grid operators and metering and communication capabilities that will enhance the ability to integrate DER into the grid. While operational concerns are critical to the ultimate success of DER integration, the economic case for it will make or break its ability to scale up significantly. Such financial considerations include market payments, reliability value, and policy incentives.

The final area of consideration, which interplays with many of the previous topics, involves figuring out the actual value of DER to the grid and how best to allocate any costs associated with integrating DER to all ratepayers who benefit from them. There is certainly no standard method at this point, and different jurisdictions are experimenting with different approaches.

## Key Considerations

The transformation of the electric grid will not happen overnight. Aligning technology, policy, and capital drivers with suitable business models that are scalable beyond local jurisdictions is a major challenge that is taking place in hundreds of cities, states/provinces, and countries today.

There are considerable lessons learned that are applicable to industry and policymakers in Ontario and other jurisdictions alike. Ontario, like many other jurisdictions, has identified key system characteristics and abiding values that are consistent with the goal of regulators and indicative of the overarching approach for all stakeholders navigating the transition in the energy sector. While resources, local politics and policy objectives, and regulations are variable by geography, most utilities are committed to nurturing an energy system that is:

- Efficient and effective with a high degree of reliability at a principle-based cost
- Appropriately leavened with competition-based pricing for as many system attributes and assets that can be reasonably accommodated
- Low carbon
- Capable of serving all of its customers and meeting their increasing expectations with a reasonable expectation of return on investment (ROI) for utilities

With a growing number of case studies, successes, and failures to review, the following key considerations are an attempt to summarise some of the most important findings, risks, and opportunities of the future of electricity supply. Key considerations include the following:

- Centralised and distributed generation can coexist, and there are benefits to such coexistence;
- Policy remains a leading driver of change, but economics is quickly catching up;
- Cost-effectiveness is still the major success factor;
- Regardless of ownership, utility-vendor relationships matter; and
- Unintended consequences from policy decisions can wreak havoc on even the most well intended plans.

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# TABLE OF CONTENTS

# INTRODUCTION

In the traditional electricity supply paradigm, centralised power plants located far outside population centres use fossil fuel, water, or uranium to generate electricity and deliver it to users over the transmission and distribution (T&D) system. The T&D system, or grid, is designed for one-way power flow with controls and safeguards that allow grid operators to constantly balance the amount of power with the amount of demand to prevent dangerous surges or drops in voltage. However, as a result of technology, policy, and financial drivers, the centralised power system is transitioning to one that is more distributed, flexible, and enables a multi-directional flow of electricity. The new more complex system is enabling the rise of the proactive consumer (prosumer) – one who actively manages their consumption and participates in the energy markets.

Industry stakeholders generally recognise that the long-term solution to meeting demand for electric power will look very different from the centralised system in place today. While the transition to the new paradigm is creating tremendous opportunities to reduce carbon emissions, it has also resulted in legitimate threats to the current utility business model. Specifically, the threat comes from new technologies and customer behaviour that reduces load served directly from the grid. As load is reduced, the cost of providing reliable centralised electricity service is distributed across fewer customers or Gigawatt hours, making distributed energy resources even more competitive. In response, early utility activities to date have largely focused on defensive measures, including the following:

- Limiting growth of net metering caps which provide incentives for distributed energy resources;
- Increasing fixed and demand charges that are independent of the volume of electricity supplied; and
- Fighting so-called “cross-subsidisation” of energy efficiency and behind-the-meter (BTM) incentives.

Centralised power generation still has an important role to play in power generation. The issue is not that centralised power generation is going away, but that the companies that currently provide the generation and transmission are going to be forced (through economics and/or regulation) to evolve. Complicating the issue is that the transition will look different in each jurisdiction depending on the relationship/differences between:

- Current power generation mix and the flexibility of those resources (gas, coal, hydroelectric, nuclear, etc.);
- Level of regulation;
- Policy environment (Renewable Portfolio Standards, net metering caps, other regional incentives, etc.);
- Price of grid supplied electricity;
- Local consumer culture and preferences;
- Public versus private utility ownership; and
- Size and composition of service territory/customer base (residential/commercial/industrial).

The rest of this report discusses the key trends and case studies that have emerged during the transition to the more distributed energy paradigm.

## KEY TERMS

**Behind the meter (BTM):** A form of generation that produces power for onsite consumption in residential or commercial facilities. A BTM system is not directly connected to the larger transmission or local distribution grid, but rather as the name implied, offsets the amount of electricity that would otherwise be purchased from the grid.

**Centralized generation:** Power system where electricity is generated at large, utility-scale power plants (typically fossil fuel plants, hydroelectric dams, nuclear plants, and utility-scale solar and wind farms). Electricity is delivered to multiple end users via a network of high-voltage transmission lines.

**Distributed energy resources:** Small-scale energy generation facilities located close to demand centres and typically composed of energy storage systems and advanced renewable technologies such as wind, solar, biomass, and geothermal power.

**Distribution:** The transfer of electricity from an electrical substation to end users. Transfer is done across shorter distances and lower voltage (less than 69 or 115 kV) power lines compared to transmission.

**Grid-connected:** A system that is connected to the electrical transmission or local distribution grid. A distributed power resource that is grid-connected may feed power into the grid in addition to supplying power to its onsite facility.

**Gigawatt (GW):** One GW consists of 1,000 MW or 1,000,000,000 watts. This unit is often used for large power plants or power grids.

**Gigawatt Hour (GWh):** One GWh consists of 1,000 MWh.

**Kilowatt (kW):** A unit of measurement of electrical power consisting of 1,000 watts. Power is the rate at which electrical energy is generated or consumed.

**Kilowatt Hour (kWh):** A unit of measurement of electrical energy equivalent to a power consumption of 1,000 watts for 1 hour. One kWh of energy will power a 100-watt light bulb for 10 hours (100 watts x 10 hours = 1 KWh)

**Megawatt (MW):** One MW consists of 1,000 kW or 1,000,000 watts. This unit is often used for large power plants or power grids.

**Megawatt Hour (MWh):** One MWh consists of 1,000 kWh.

**Stranded asset:** An asset that due to various economic, political, or environmental factors has become obsolete or a liability ahead of the end of its useful life. Fossil fuels such as coal that remain in the ground, unused due to environmental energy policies, are considered a stranded asset.

**Transmission:** The transfer of electricity from an energy source (power plant) or load to an electrical substation. Transfer is done via high-voltage (more than 69 or 115 kV) electrical power lines.

# PART I: CENTRALISED GENERATION

# 1. TRENDS

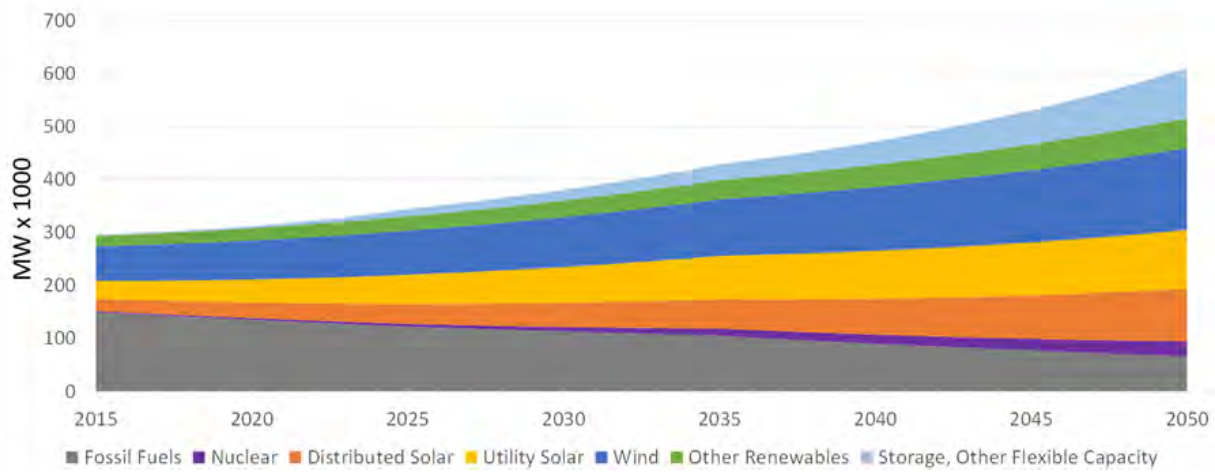
Centralised generation is generally characterised by the capital costs, low operations and maintenance (O&M) costs, and varying fuel costs that all depend on region and regulatory regime. For the most part, these assets are financed over a period of 20-30 years. Historically, utilities have operated as regulated monopolies and had consistent access to low-cost capital, which has enabled the companies to invest in centralised generation systems while earning a fair return for investors. In several regions, utilities have undergone a transition to competitive markets and deregulation, which has resulted in greater pressure to procure low-cost power. The transition to competitive markets was aided by innovation in centralised power generation technologies and, in some regions, lower fuel costs.

Notable developments affecting centralised power generation technology include the following:

- **Decreasing natural gas fuel costs:** Particularly led by discovery and extraction of shale gas;
- **Coal power plant retirements:** Both regulatory driven and due to low-cost natural gas;
- **Upgrading of hydroelectric and nuclear power plants:** Efficiency improvements to power plants result in significant increases in existing facilities and negating the need to undergo a permitting process that could last decades;
- **China's 5-year energy plans:** China's massive energy investments make it the leading source of both renewable and non-renewable power capacity additions, driving dramatic cost reductions for components;
- **Transition to renewables:** New investment in renewable deployments reached approximately CAD$360 billion[1] (US$270) in 2015 and is expected to increase 5 to 7 percent globally each year over the next decade; and
- **Need for energy storage:** In regions with higher penetration of large-scale renewables, energy storage will be a required for firming power, making renewable energy dispatchable.

The shadow cast by these trends is significant when reviewed over a 35-year time horizon, as illustrated in Figure 1-1.

**Figure 1-1. Annual Generation Capacity Additions by Technology, World Markets: 2015-2050**



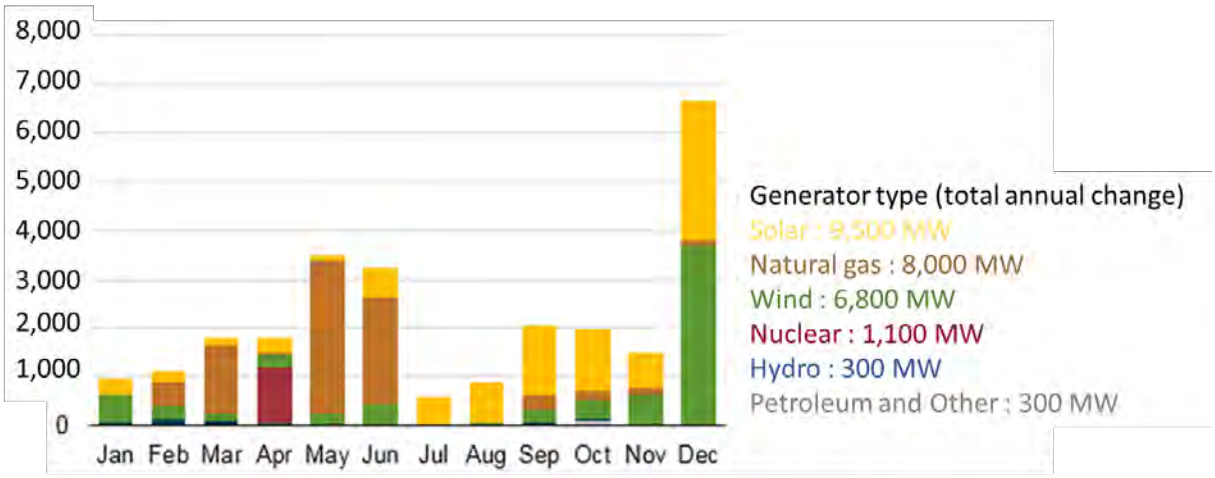

*Source: Navigant Research*

[1] All values in this report are in CAD, unless otherwise stated. Foreign currencies have been converted to CAD using the average exchange rate in the first quarter of 2016. CAD$1 = US$ 0.752

In general, fossil fuels are expected to decrease significantly as a percent of new power generation capacity additions. Distributed energy resources are also expected to make up a growing share of new capacity additions, in particular solar and storage.

While there has been significant coverage of the energy transition that has occurred in Europe—led by Germany (Energiewende)—North America is now experiencing a similar transition. In the United States, solar PV, wind, and natural gas are expected to account for approximately 95percent of new capacity additions in 2016 (Figure 1-2). The combination of the long-term extension of important wind and solar tax credits, state-level renewable deployment targets and record-low natural gas prices is leading to a less carbon-intensive and more flexible portfolio of electricity generation.

**Figure 1-2. Scheduled Electric Generating Capacity Additions (MW), United States: 2016**




*Source: U.S. Energy Information Administration*

The need for centralised generation to be flexible and for the system to be compatible with distributed energy resources are two of the most pressing issues facing the electric power sector when looking out to 2050, creating both challenges and opportunities for utilities today. Strategies and key trends related to these and other important factors are discussed throughout the remainder of this report.

# 2. TECHNOLOGIES

Table 2-1 reviews the current state of centralised power generation technologies across cost, operational, emissions, and region of leading market activity. More detailed technology profiles follow.

**Table 2-1. Representative Power Plants**

| Technology | Cost Summary | Installed Cost ($/kW) | Pro | Con | Emissions | Region of Activity |
|---|---|---|---|---|---|---|
| Hydro | High capital costs, long permitting cycles, potentially very low operating costs | CAD$4,000-8,000 (US$3,000-6,000) | Very predictable, baseload power, in some instances dispatchable | Susceptible to cost overruns and external costs (displacement, environmental impact not often included in cost) | None | China, Brazil, Democratic Republic of Congo, SE Asia |
| Nuclear | Very high capital costs, significant regulatory and financing challenges for new projects lasting decades | CAD$4,000-16,000 (US$3,000-12,000) | Very predictable, baseload power | Highly susceptible to cost overruns, waste storage issues, safety concerns; does not ramp up or down well | None | China, United States, United Kingdom |
| Natural Gas Power Plants | Versatile technology used in peaking applications or as baseload power; low capital cost, but subject to volatile natural gas fuel prices | CAD$665-2,660 (US$500-2,000) | Very low cost, widely deployed, often sets effective marginal rate for new power procurement; very flexible and complimentary to intermittent renewables | Subject to volatile natural gas fuel prices; risk for negative impact on water sources from hydraulic fracturing | Typically 50 percent less emissions than coal from combustion; however, methane leakage likely higher than currently reported, potentially reducing carbon savings | Global |
| Biomass | Proven technology increasingly used as fuel-switching/co-firing option for coal plants; can be new or retrofitted into existing coal plants | CAD$4,000-6,650 (US$3,000-$5,000) | Provides predictable baseload power; provides opportunity to utilities otherwise faced with coal shut downs | Vulnerable to biomass pellet market fluctuations, potentially restricted in some regions that do not consider biomass renewable | Typically less emissions than coal | United States, United Kingdom, Canada |

| Technology | Cost Summary | Installed Cost ($/kW) | Pro | Con | Emissions | Region of Activity |
|---|---|---|---|---|---|---|
| Coal | Low capital costs, but subject to volatile fuel costs | CAD$1,330-4,000 (US$1,000-3,000) | Proven baseload technology; historically abundant fuel | Older projects not economical; subject to current and impending emissions regulations | Highly polluting, unless installed with scrubbers and/or carbon capture and storage (CCS) systems | China, India |
| Solar PV | Low (and decreasing) capital costs, no fuel costs | CAD$1,330-2,400 (US$1,000-1,800) | Often cheapest form of new power generation; not subject to volatile fuel costs | Intermittent, non-dispatchable (unless storage added, increasing cost) | None | China, United States, South Africa, Brazil, Chile, India, Japan, Canada |
| Wind | Low (and decreasing) capital costs; offshore significantly more expensive than onshore; no fuel costs | CAD$1,700-4,000 (US$1,300-3,000) | Widely deployed renewable technology, higher efficiency than solar; no fuel inputs | Intermittent, non-dispatchable (unless storage added, increasing costs) | None | China, Brazil, United States, United Kingdom, Germany, India, Canada |

*Compiled by Navigant*

## 2.1 Natural Gas

Natural gas-fired electricity can include turbines that are driven directly by gases produced by combustion or by both natural gas and steam (combined cycle). Gas-fired electricity generation can play a pivotal role in a centralised electricity grid, as it is able to ramp up and provide electricity at a faster rate than baseload sources such as nuclear. This ramp is required to meet times of the day when demand is increasing or decreasing quickly (such as in the morning or early evening). The attractiveness of natural gas power plants has increased significantly with the increased availability of low-cost shale gas, particularly in North America and the Middle East. Most of Europe and Asia are still paying relatively high costs or natural gas, but with the expansion of new pipelines from Russia and liquefied natural gas (LNG) terminals coming online, the prospect for LNG import is increasing globally, leading to greater opportunities for natural gas power plants worldwide. With 50 to 60 percent fewer carbon emissions than coal, natural gas is realising its role as a so-called bridge fuel, though dependency on natural gas power introduces significant fuel price risk over the long-term.

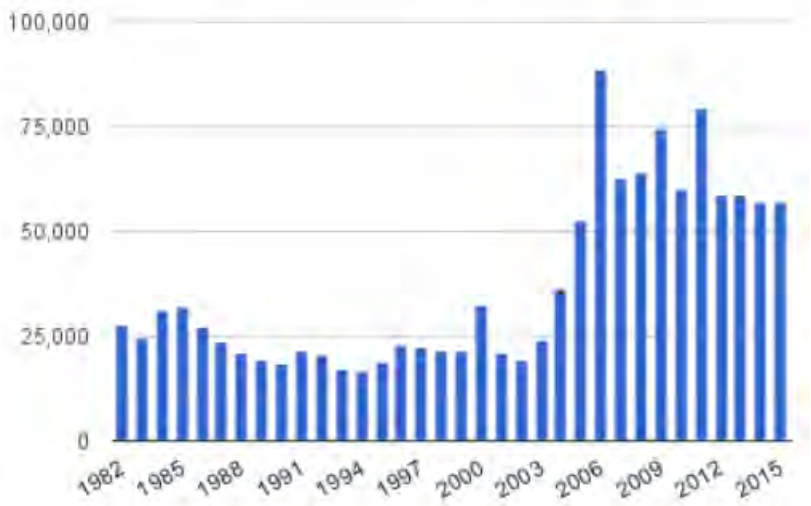
## 2.2 Coal

Coal-fired electricity generation is a significant source of energy supply for the world. It has the highest carbon content of all fossil fuels and is a large contributor to greenhouse gas (GHG) emissions. While many jurisdictions rely on coal for electricity generation, there is a general shift away from coal in favour

of renewables or natural gas. Technologies such as carbon capture and storage (CCS) or other pollution control devices can play a key role in reducing the impacts of coal use.

Ontario phased out its last coal plant in 2014. Other countries such as Scotland have also recently shut down their last coal plant. However, India and China have added approximately 100,000 MW and 300,000 MW of coal capacity since 2010—accounting for 85 percent of all new coal capacity. Net retirements have still ranged between 55,000 and 85,000 MW during the past 10 years. Concerns of oversupply and a softening economy in China, paired with the equally as ambitious rollout of renewables—including hydro, wind, and solar—and nuclear, may result in further reduction of coal deployment in China.

**Figure 2-1. New Coal Power Worldwide, Net of Retirements: 1982-2015 (MW)**




*Sources: 1982-2009, Platts WEPP, December 2015; 2010-2015, Global Coal Plant Tracker, January 2016, and Sierra Club. Figures for 2015 preliminary.*

## 2.3 Hydroelectric

Hydroelectric power can refer to any electricity that is generated by water (either falling or flowing). Forms of hydroelectric power include dams, pumped storage, or run of river. Dams generate electricity by using the power of dammed water to turn a turbine and generator. Pumped storage transfers water between reservoirs, pumping water into a higher reservoir when demand is low and then releasing the water back down and through a turbine when demand is high. Run of river has no (or very little) reservoir capacity. Electricity is generated by water flowing down a river or stream that turns a turbine. The majority of hydroelectric generation facilities are transmission-connected; however, distribution-connected facilities do exist in Ontario. Large hydropower facilities in regions such as Canada and the U.S. Pacific Northwest have enabled higher penetration of wind power, with the dams essentially serving as a battery.

## 2.4 Nuclear

Due to technical limitations, nuclear power is difficult to ramp up or down. Therefore, it is often used as a source of baseload power in a generation mix. The cost of building nuclear is driven by the upfront cost of capital associated with construction, with costs varying significantly between jurisdictions. In addition, there are significant uncertainties associated with nuclear construction times, often resulting in delays in construction and significant price increases. While the prospect of emission-free baseload power is

enticing from a resource planning perspective, public opposition to building new nuclear plants is common. Nuclear power plants pose safety concerns for transport and storage of nuclear waste, making them difficult to finance, often requiring government support in the form of loan guarantees.

## 2.5 Utility-Scale Wind

Utility-scale wind typically consists of multiple wind turbines that combined have the capacity to produce 100 MW or more of electricity. Utility-scale windfarms can be considered centralised power generation system when located in remote areas away from large population centres with abundant wind resources. Large-scale onshore wind farms utilise wind turbines typically around 1 MW to 2 MW with 63,000 MW installed in 2015—nearly half in China—for a cumulative installed base of 433,000 MW. The offshore wind market is still in its infancy compared to onshore wind; Europe and, to a lesser extent, Asia are the only regions to tap into this market. Offshore wind farms typically have larger turbines on the order of 4 to 5 MW or more with rotor diameters commonly reaching 150 meters, as offshore foundations are better suited for these larger units. The majority of large-scale wind farm generation is bought and sold on the wholesale power market either contractually or through a competitive bid process prior to being delivered to customers.

In Ontario, the Large Renewable Procurement (LRP) is a competitive process for procuring large renewable energy projects (over 0.5 MW). The LRP is an important component of Ontario's ongoing commitment to building a cleaner and more sustainable energy system, and represents a key step in the province's 2025 target for renewable energy to comprise about half of Ontario's installed capacity. Targets for the first procurement, completed in 2016, included 300 MW of wind, which was oversubscribed by approximately 2,000 MW and resulted in contracts averaging approximately CAD$86/MWh. This suggests considerable potential for the further development of wind projects in Ontario.

## 2.6 Utility-Scale Solar PV

Utility-scale solar PV plants can be considered a centralised form of power generation when on the order of 50 MW or larger. Solar farms on this scale have been typically owned and operated by independent power producers (IPPs); however, utility-owned projects are becoming more common. Government incentives such as Production Tax Credits have played a large role in supporting solar photovoltaic farms to date. However, as solar costs continue to decline, these incentives will become less necessary for these plants to be cost-competitive in the energy market. Recent auctions for utility-scale solar plants in favourable jurisdictions have yielded power purchase agreements in the CAD $40 to 70/MWh (US$30 to $50) range and are expected to continue to decline. Today, utility-scale power plants are being installed without subsidies in regions with strong solar resources including the Middle East and South America.

Targets for Ontario's first round of the LRP included 140 MW of solar, which was oversubscribed by approximately 1,600 MW and resulted in contracts averaging approximately CAD$157/MWh.

## 2.7 Next-Generation Technologies

New technologies and improvements to existing technologies offer varying levels of promise for large-scale energy supply, including grid-scale storage, new nuclear power plant designs, and Carbon Capture and Storage (CCS). Distributed energy resources, the local conditions, regulatory framework, utility risk appetite, and resource mix are highly influential for establishing whether new centralised technologies are a good fit. The following sections summarise some of the key technologies and trends in next-generation, large-scale power generation and enabling technologies.

### *2.7.1 Grid-Scale Energy Storage*

Energy storage systems can provide benefits to grid operators in a variety of ways. Daily applications include providing firm capacity reserves and system wide peak shaving when demand is high. On the timescale of tens of minutes to a few hours, energy storage can help smooth the output of variable renewable energy generation. Over timeframes of seconds to minutes, energy storage can help with frequency regulation and voltage support. Ultimately, energy storage can help defer or avoid traditional investments in generation (peaking plants) as well as T&D.

Energy storage spans a number of technologies such as batteries (Li-ion, advanced lead-acid, sodium metal halide, and others), compressed air energy storage, thermal energy storage, and flywheels.

The most commonly deployed and cost-effective grid-scale energy storage technology is pumped hydro. Pumped hydro refers to water from a river being pumped up to the reservoir of a hydroelectric dam. More than 292 pumped storage hydro facilities are in operation worldwide, with total capacity of 142,000 MW. Another 46 projects, with total capacity of 34,000 MW are being developed according to the U.S. Department of Energy Storage Database.

Italy, currently has 2,304 MW of online energy storage resources, with around 99 percent coming from pumped hydro systems. Italy, however, like many jurisdictions or utilities around the world are also experimenting with new battery-based, grid-scale energy storage technologies such as Lithium-ion (Li-ion) batteries. Perhaps the most notable new projects are the two 35 MW sodium sulphur battery systems being deployed by grid operator Terna S.p.A and vendor NGK Insulators. These energy-dense systems will provide a combined 490 MW mixing energy and capacity on the grid. Terna has demonstrated a commitment to utilising energy storage to increase the security of its electrical grid and integrate solar power with two storage labs for power-intensive projects (located in Sardinia and Sicily). These projects include a wide range of electrochemical storage systems like flow batteries, Li-ion batteries, and capacitors.

Utilities in North America, Europe, and Asia have emerged as the top consumers of energy storage for both large, utility-scale systems and smaller, distributed systems. These consumers include municipal, vertically integrated, and investor-owned utilities and merchant third-party developers. In 2014 and 2015, utilities worldwide deployed roughly 124.3 MW of energy storage capacity, accounting for about 23 percent of all systems deployed during that time period. Currently, utility-owned energy storage systems account for 27 percent of the global energy storage system pipeline. Nearly 9,000 MW of new utility-owned energy storage capacity is expected to be deployed by 2020.

#### *Utility Energy Storage Strategies*

Utility interest in storage has coincided with a noticeable decrease in system pricing and successful technology demonstrations. This interest has shifted energy storage out of the innovation department of major utilities and into the commercial business side and the resource planning groups. Although many utilities are still struggling to make a case for energy storage, the value of energy storage is much clearer today compared to 2013. Today, the emphasis is on how quickly regulators will catch up to utilities and allow them to fully monetise energy storage systems. Broadly speaking, utilities are developing an understanding of whether storage is a threat or opportunity to businesses and developing strategies to transform perceived threats into opportunities.

#### *Australia*

Due to the overbuild of network infrastructure over the previous decades, Australia has some of the highest electricity prices in the world, with consumer rates around CAD$390 per MWh (US$290). This situation, coupled with the high penetration of distributed solar in much of Australia, has led to one of the

most dynamic and attractive markets globally for distributed energy storage systems. There is a strong desire among many Australians to maximise self-consumption of solar generated electricity, given the varying compensation they receive when sending surplus power back to the grid. As behind the meter energy storage paired with solar transfers value away from the incumbent electricity provider, several utilities in the country are taking proactive steps to get involved in the distributed energy storage system business. Three of the country's larger utilities—Red Energy, Ergon Energy, and ActewAGL—announced trials in 2015 to offer battery energy storage systems to residential customers. This plan will allow the utilities to enter the market before most third-party providers, ensuring customers remain part of their utility network and that these energy storage systems can be utilised to support overall system stability.

#### *Texas*

Texas is a leader on this front, with 14 energy storage projects greater than 0.01 MW deployed, under construction, or announced. Six of those projects are 0.5 MW or more. In 2012, Duke Energy installed the largest energy storage project in the state, a 36 MW advanced lead-acid battery energy storage project at the Notrees Wind Farm. Another project, the Big-Old Battery (BOB) is a 4 MW sulphur sodium battery providing backup power to the town of Presidio that currently operates with an aging transmission grid and is vulnerable to outages from powerful electrical storms on the Texas plains. Oncor, the state's largest transmission company, installed six battery storage systems in 2014 in South Dallas neighbourhoods, providing backup power to schools, traffic lights, and a fire station. The company recently proposed plans for energy storage projects on a much wider scale—CAD$7(US$5.2) billion in all—to improve reliability.

#### *China*

China is expected to be a major market for energy storage systems in the coming years for a number of reasons. Chief among them is the rapid growth of renewable energy over the past few years. In particular, China has installed an enormous amount of wind generation, which the country's grid is not currently able to handle efficiently—with as much as 20 to 30 percent of power generated currently wasted according to the Chinese National Energy Agency.[2] There are significant transmission constraints on the Chinese grid, with plentiful wind power not always being able to reach population centres where it is needed. This has resulted in widespread curtailment of wind power—a major concern for plant owners and a driver for the energy storage system market. Grid-scale energy storage systems can allow currently curtailed wind power to be captured as it is generated and then delivered to the transmission system whenever capacity becomes available. This can result in less costly energy for end users as well as a more reliable system.

### *2.7.2 New Nuclear*

When it comes to nuclear power, the role of government is more crucial than any other power generation technology—from both a financing and public safety standpoint. As such, the prospect for expanded nuclear in the post-Fukushima world will remain highly dependent on the politics of each country or sub-national jurisdiction.

#### *China's Domestic Deployment of New Nuclear Plants*

China is continuing its highly ambitious deployment of electricity generation across all technologies domestically and continues to have a major impact when it comes to exporting its technology as well. China's most recent targets call for an astounding 200,000 MW of solar, 250,000 MW of wind, and a steady rollout of nuclear power that is targeting 58,000 MW by 2021, 150,000 MW by 2030, and as much

[2] http://insideclimatenews.org/news/28032016/china-wind-energy-projects-suspends-clean-energy-climate-change

as 400,000 to 500,000 MW by 2050. By far, China is leading the global nuclear market, which totalled CAD$24 (US$18.1) billion in 2015, up 13 percent over 2014—though still down from a five-year peak of CAD$54 (US$40.8) billion in 2011.

### *China's Overseas Sales of New Nuclear Plants*

According to the World Nuclear Association, China is currently home to 30 operating nuclear power reactors, with an additional 24 under construction and more about to start construction, which means the country's targets (like solar and wind) are on path to be achieved. Like solar and wind, the government is also taking a "going global" approach to nuclear by exporting nuclear technology, including heavy components in the supply chain.

Some of the earliest customers for China include the following:

- EDF Energy and China signed a deal to build the 3,200 MW Hinkley Point nuclear power plant worth CAD$34.4 (GBP£18) billion[3] in late 2015.
- Pakistan struck deals with Chinese vendors for four nuclear power plants at two sites totalling approximately 4,000 MW at a cost of nearly CAD$16 billion (US$12).
- Chinese General Nuclear Power Corp signed a deal worth CAD$ 10.4 (US$7.8) billion to construct two additional units at the Cernavoda plant in Romania, each with a capacity of at least 720 MW.
- Argentina signed deals with Chinese National Nuclear Corporation worth CAD$7.7 billion (US$5.8) for an 800 MW project.

### *Revival of nuclear generation activity in U.S.*

In late 2015, federal regulators approved an operating license for Tennessee Valley Authority's (TVA's) 1,150 MW Watts Bar 2 Unit—nearly 43 years following its initial permit to begin construction was granted. According to World Nuclear News, construction of Watts Bar 2, a pressurised water reactor, began in 1972, but work was suspended in 1985 when the unit was about 55 percent complete. TVA restarted work on the unit in 2007 and awarded Bechtel the engineering, procurement, and construction contract to bring the unit online. Together, Unit 2 and Watts Bar's (already operating Unit 1) will have a rated capacity of 2,300 MW.

### *Future Prospects of Next-Generation Nuclear, Including Small Modular Reactors*

As talk of a nuclear renaissance has gained credence, the nuclear power industry may have begun to reverse its historic reliance on large-scale reactors. Smaller reactors, which can be built in factories, assembled onsite, and arrayed in multiple reactor configurations to incrementally scale up capacity, have caught the attention of vendors, technology developers, power generators, and government regulators. These miniaturised reactors are known as small modular reactors (SMRs). In theory, SMRs counter the economies of scale offered by larger facilities with economies of mass production and standardisation, lower upfront capital costs, enhanced safety features, flexible deployments, and innovative fuel cycles. They also offer a broader range of applications—from heat for industrial processes to distributed generation and water desalination.

Many believe that SMRs represent not only the future of nuclear power but also a vehicle for the rebirth of the moribund nuclear power industry in the United States. In countries such as France, China, and

[3] CAD$1 = GBP£0.523, Foreign exchange currencies have been converted to CAD using the average exchange rate in the first quarter of 2016

Russia, SMRs are seen as a potential driver of economic competitiveness and sources of sustainable electricity.

### *2.7.3 Carbon Capture and Storage*

Carbon capture and storage (CCS) is a process by which carbon dioxide ($CO_2$) is captured from the air, compressed to a critical liquid for transportation, and stored long-term in geologic or marine applications. Typically, carbon capture is applied to stationary, fossil fuel-based processes such as coal- and gas-fired power generation, natural gas processing, and fertilizer production, as well as industrial processes such as cement, iron, steel, pulp, and paper. Novel carbon capture technologies are being developed to capture $CO_2$ from ambient air. For power generation and industrial applications, $CO_2$ can be captured in the pre-combustion phase, post-combustion phase, or through oxyfuel combustion. The most commercially viable application of CCS is believed to be pre-combustion capture via integrated gasification combined cycle (IGCC) used with CCS, which is commonly referred to as IGCC-CCS. An IGCC plant uses a gasifier to turn coal into a gas. This case is referred to as synthesis gas (syngas). Because syngas is produced from a single stream from the gasifier, it can be purified before combusting it or processed in a shift reactor to generate a pure stream of $CO_2$ to be captured and sequestered. At the time of this report, nine IGCC-CCS plants were operating worldwide.[4] The $CO_2$ from these plants is transported and stored in geologic formations on land or under the sea. More advanced storage options include marine sequestration by which $CO_2$ is dissolved in deep seawater under high pressures.

The deployment of IGCC-CCS is highly dependent on policy drivers, such as a carbon tax or carbon cap and the cost of competing generating technologies such as natural gas, solar, and wind. This technology is most attractive where there are storage options within 100 miles and inexpensive, high-quality coal. There are several major pilots underway to research the long-term implications of carbon storage. Enhanced oil recovery (EOR), whereby $CO_2$ is injected into depleting oil and gas reservoirs and dissolves into the oil or gas and enhances its viscosity so that it can be recovered, is considered the most commercially viable option. As of 2010, there were approximately 210 EOR projects worldwide.[5]In the United States alone, there are approximately 114 active commercial $CO_2$ injection projects that inject a cumulative two billion cubic feet of $CO_2$ and produce over 280,000 barrels of petroleum per day.[6] Besides the financial benefit of increased petroleum recovery, EOR is considered ideal for sequestration because it uses formations that have the proven ability to hold hydrocarbons over geologic time, have existing pipeline transportation and injection infrastructure, have existing monitoring facilities to observe $CO_2$ residence underground, and occur in areas where the public has already widely accepted oil and gas wells so will likely accept injection projects.

IGCC-CCS covers the full lifecycle of CCS, as illustrated in Figure 2-2. While IGCC and transportation technologies are well understood, capture technologies are still evolving, and the long-term effects of carbon storage are still under investigation.

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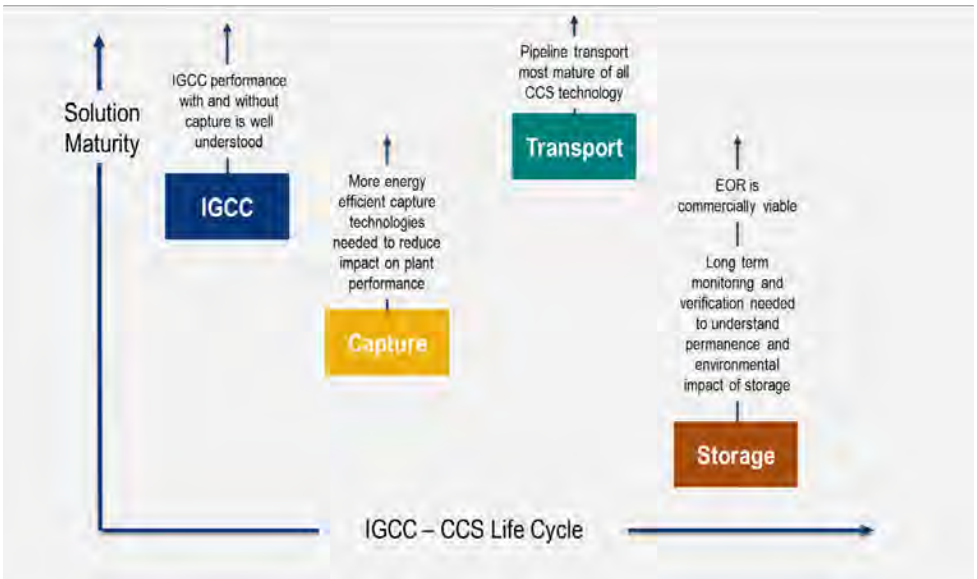
[4] According to the Global CCS Institute, these are projects that are large-scale. The Global CCS Institute defines large-scale as a project involving the capture, transport, and storage of $CO_2$ at a scale of 800,000 metric tons of $CO_2$ annually for a coal-based power plant and at least 400,000 metric tons of $CO_2$ annually for other emissions-intensive industrial facilities (including natural gas-based power generation). This analysis focuses on IGCC-CCS, a coal-based power plant technology (http://www.globalccsinstitute.com/projects/large-scale-ccs-projects-definitions).

[5] http://neori.org/Melzer_CO2EOR_CCUS_Feb2012.pdf

[6] http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery

**Figure 2-2. IGCC-CCS Offering Classes**




*Source: Navigant Research*

### *Technology Trends and Issues*

The two greatest issues affecting CCS development are a lack of climate policy and carbon taxes as well as a limited understanding of geologic storage availability.

IGCC-CCS is a well-understood technology that is already deployed. Given the high capital costs of these plants compared to conventional coal-fired generation technology and the energy penalty involved in capturing $CO_2$, these plants are not financially competitive unless there is an opportunity to use the $CO_2$ for commercial applications such as EOR. EOR was first tested at a large scale in the Permian Basin of West Texas and south-eastern New Mexico in the United States during the 1970s. There is some speculation over whether $CO_2$ can be used to enhance water recovery, but this technology has not been demonstrated on a wide scale. An experimental case study is underway in Western China to determine how $CO_2$ can be sequestered in enhanced water recovery operations.[7]

To prove that IGCC-CCS with geologic sequestration is a viable option to permanently store $CO_2$, additional research is needed to understand the behaviour and characteristics of storage reservoirs. The physical characteristics of the site will determine injection rate, which influences the rate of capture. The location dictates the cost, permitting, and siting process for a pipeline to transport $CO_2$ from the source to the storage reservoir. Evaluating and confirming a new saline formation's storage capacity takes five to 10 years.[8] While building a capture plant takes less time, identifying a suitable storage site may create delays in project implementation. Lastly, technology for long-term storage monitoring to verify that $CO_2$ remains sequestered is still in development. Although EOR has been used since the 1970s, technologies to monitor $CO_2$ in place have not been widely used. Technical understanding of $CO_2$ seepage and abilities to detect it are not yet understood on long-term scales.

[7] http://www.cagsinfo.net/pdfs/cags2-workshop1/7-2QiLi-Revised.pdf

[8] https://www.iea.org/publications/insights/insightpublications/Insight_CCS2014_FINAL.pdf

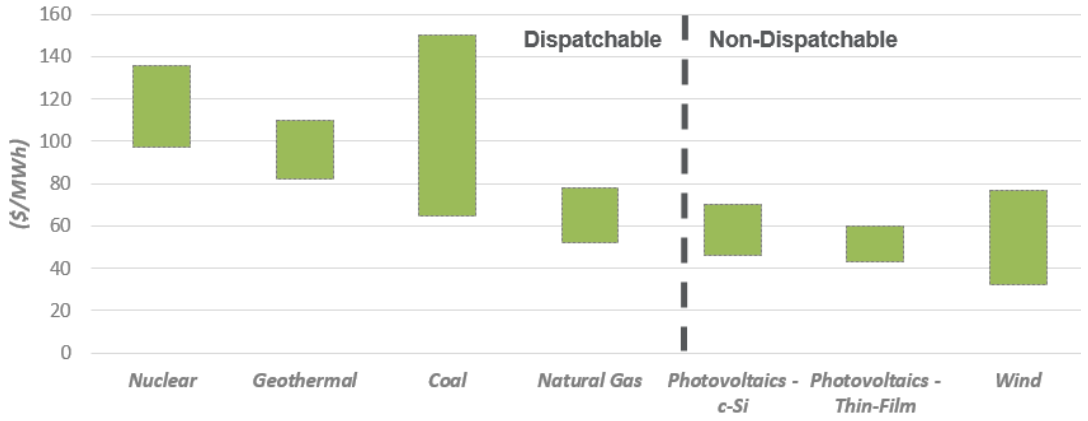
# 3. COST CONSIDERATIONS

Cost has and will remain one of the most important drivers for centralised power generation. Utilities, with guidance from regulators, have historically harvested the most abundant and lowest-cost natural resource, resulting in a buildout of large-scale hydropower projects, coal, and natural gas power plants. Emissions regulations, volatile fuel costs, and government mandates for renewable energy deployment, permitting, and other local factors have resulted in a more complex framework for deciding which power generation technologies should be added or removed from a utility portfolio. Increasingly, utilities and system operators must navigate the complexity of increased intermittency with higher penetration of both large-scale renewables such as wind and solar farms and behind the meter applications such as distributed solar, and increasingly energy storage, fuel cells, micro turbines, and other distributed generation technologies.

As the most commonly used method for comparing the attractiveness of competing power generation technologies, an analysis of the levelised cost of electricity (LCOE) takes into account the total capital, maintenance, financing, and other costs of a system and divides it by the total power production over the financial life of the project. The result is an effective cost per MWh that can be used to compare technologies.

In general, the relative importance of the LCOE inputs varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight construction cost estimates significantly affect LCOE. Financing terms can also have a significant impact on LCOE as well as carbon and other environmental costs, which were not included in this analysis. The availability of various incentives, including tax credits, can also influence the calculation of LCOE. Figure 3-1 represents a current snapshot of the LCOE range for various power generation technologies worldwide.

**Figure 3-1. Unsubsidised Levelised Cost of New Energy Generation**

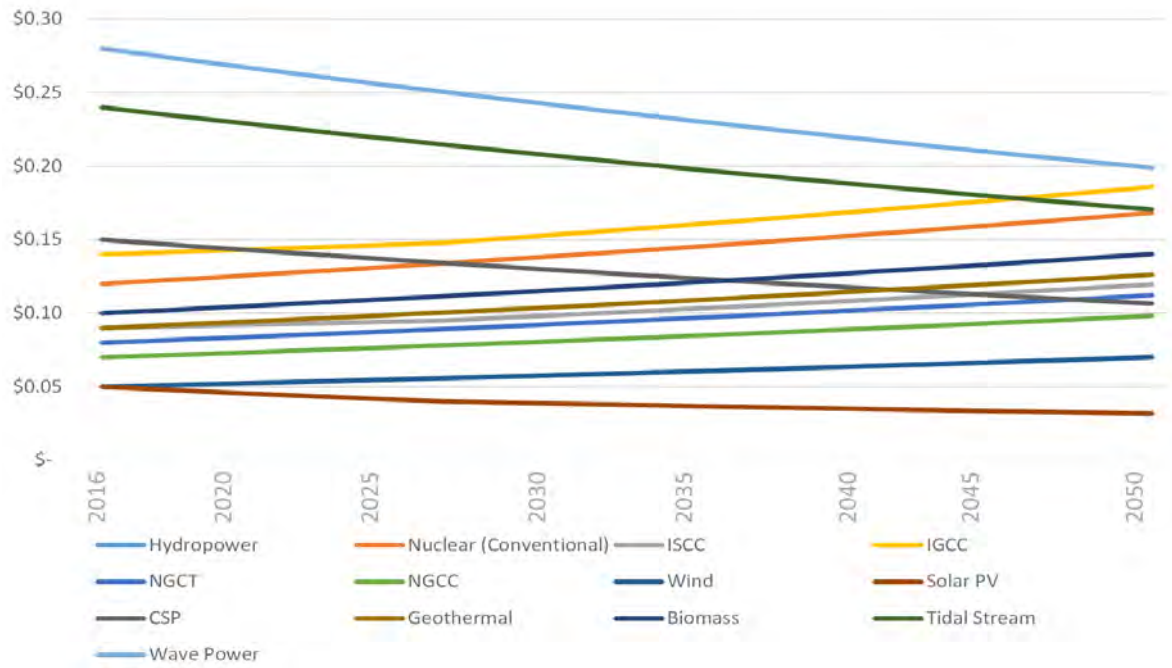



*Source: Navigant Research*

Figure 3-2 presents Navigant's representative global average forecasts for major centralised power generation technologies. In general, capital costs are expected to decrease or stay flat across all of the technologies. However, technologies that rely on natural gas fully (such as natural gas combined cycle, gas turbines, etc.) or partially will see the benefits of capital cost reductions eroded by increases in natural gas pricing during the forecast period—except in Asia Pacific and Europe. These regions are expected to see natural gas price reductions in the near term (and then continue to increase in the medium term). Solar and wind are expected to see continued capital cost reductions while requiring no

fuel costs, resulting in attractive LCOEs—especially in the medium term—relative to the competing technologies.

**Figure 3-2. Average LCOE Results, Reference Case, World Markets: 2016-2050**




*Source: Navigant Research*

# 4. POLICIES

## 4.1 Unbundling and Deregulation

Unbundling refers to the process of requiring vertically integrated utilities (which have a monopoly) to split into discrete entities—typically characterised as generation companies, regulated T&D utilities, and retail electric providers. In some cases, such as Texas, these entities were required to function separately, even if they remained under the same corporate ownership. Under deregulation, jurisdictions introduced competition into the generation and/or retail electricity markets.

- **Generation companies:** Under deregulation, generation companies are expected to compete with one another on price. However, some generation companies have begun pressing for artificial price supports, claiming the deregulated system is not providing them with enough revenue to justify new investment.
- **T&D utilities:** The power produced by generation companies travels across the system of wires owned by T&D utilities. These wires companies generally retain their monopoly status and remain rate regulated.
- **Retail electricity providers:** Under deregulation**,** retail electricity providers purchase power in the wholesale markets and sell directly to residential and commercial consumers. They are typically free to set their own price for power.

Several jurisdictions around the world have undergone this transition to an unbundled and deregulated market, including the UK, parts of US, Alberta and Australia. Other jurisdictions have unbundled, but have limited deregulation. In Ontario for example, there is effectively no retail electricity market and the vast majority of generation is either regulated or under long-term contract with the government.

The state of unbundling and deregulation in a particular jurisdiction is important when it comes to the future of centralised generation. The greater the extent of deregulation the bigger the impact of market forces (e.g., decreasing costs of distributed energy resources). In jurisdictions that are vertically integrated or largely regulated, policy if often a more impactful driver of change.

## 4.2 Emissions Regulation

Emissions regulations have played an important role in Europe and will increasingly play a significant role in North America. The recently signed COP 21 Paris Accord will also open the door to greater consideration for emissions reduction in developing countries. Such regulations will foster a preference towards energy production from low emission sources – wind, solar etc.

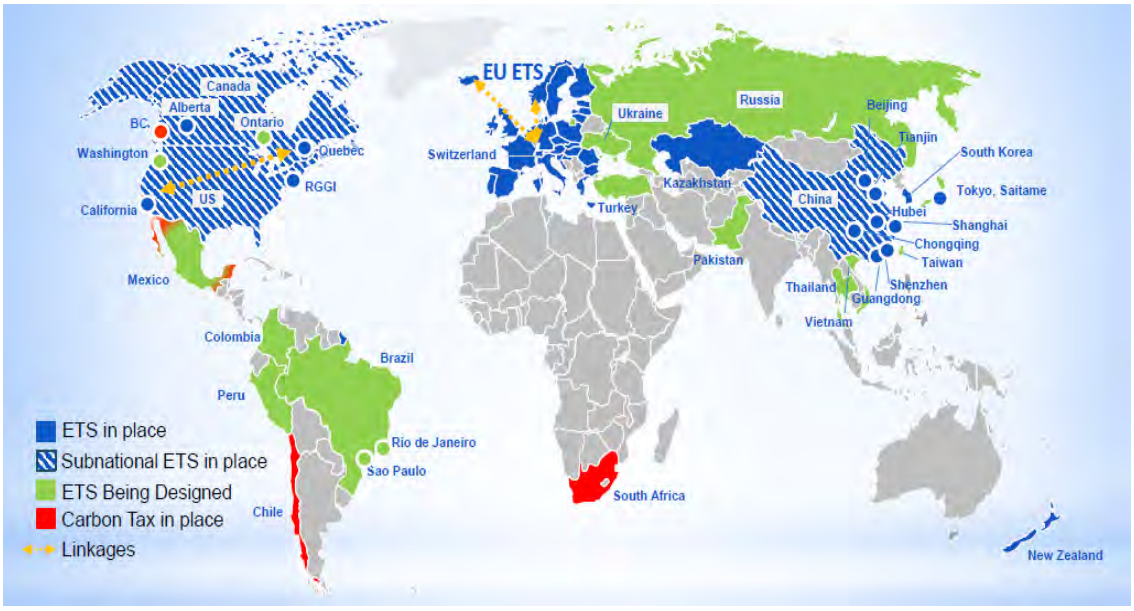
### *4.2.1 Carbon Pricing*

Putting a price on carbon has emerged as a policy and economic instrument to help drive GHG emissions reductions and investment into alternative technologies. Carbon pricing can take a number of forms, with a carbon tax or a cap and trade system being the two most prevalent options.

As illustrated in Figure 4-1, existing carbon markets in North America include the Regional Greenhouse Gas Initiative, which covers emissions from power plants in eight north-eastern U.S. states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, and Rhode Island) and the Western Climate Initiative (WCI). WCI members currently include Quebec and California, with expectations that Ontario will link to this market in 2017.

Other carbon markets in North America include British Columbia's carbon tax and Alberta's baseline and credit program, which has flexible compliance mechanisms similar to a cap and trade program. Mexico also has a carbon tax in place and is in the process of developing a cap and trade program.

**Figure 4-1. Carbon Pricing around the World**




*Source: International Emissions Trading Association*

### *4.2.2 Clean Power Plan*

Though currently on hold, the U.S. Environmental Protection Agency's (EPA's) final Clean Power Plan (CPP) is expected to move forward and place $CO_2$ emission standards on existing fossil fuel-fired electric generating units. The EPA's final rule establishes separate $CO_2$ emission rate limits for fossil fuel-fired steam generating units and natural gas combined cycle units but allows states to choose an alternative equivalent state rate or state mass goal. Each state must submit a plan to the EPA outlining how it intends to comply with the CPP. The final targets of the rule are derived from three building blocks: potential heat rate improvements at existing coal-fired plants, shifting coal-fired generation to natural gas, and increasing renewable generation. However, the EPA makes clear that measures outside of these three building blocks may also be used to comply with these requirements, opening the door to distributed energy resources, for example.

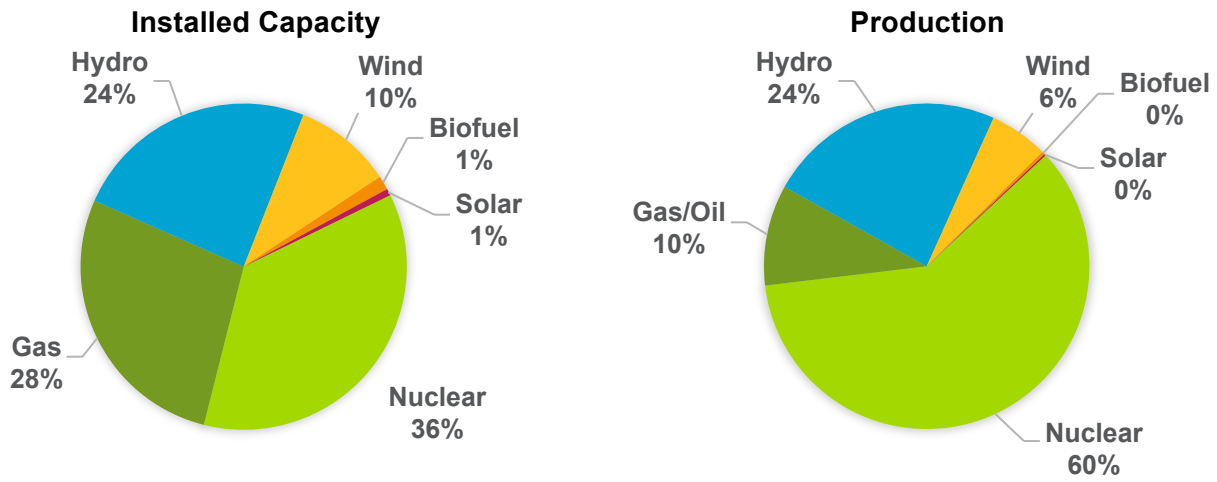
# 5. JURISDICTIONS IN TRANSITION

The following sections highlight some of the most active countries undergoing energy transition and sub-national jurisdiction.

## 5.1 Ontario

Nuclear, hydro, and natural gas account for approximately 90 percent of Ontario's 35,590 MW of installed electricity generation capacity today, as illustrated in Figure 5-1. Correspondingly, these fuels also represent a large percentage of the total electricity produced in Ontario (approximately 95 percent or 144,000,000 MWh in 2015). This represents a material change from 10-years ago, when coal-fired generation comprised a significant portion of the overall electricity supply in Ontario.

**Figure 5-1. Ontario's Current Supply Mix: 2015**



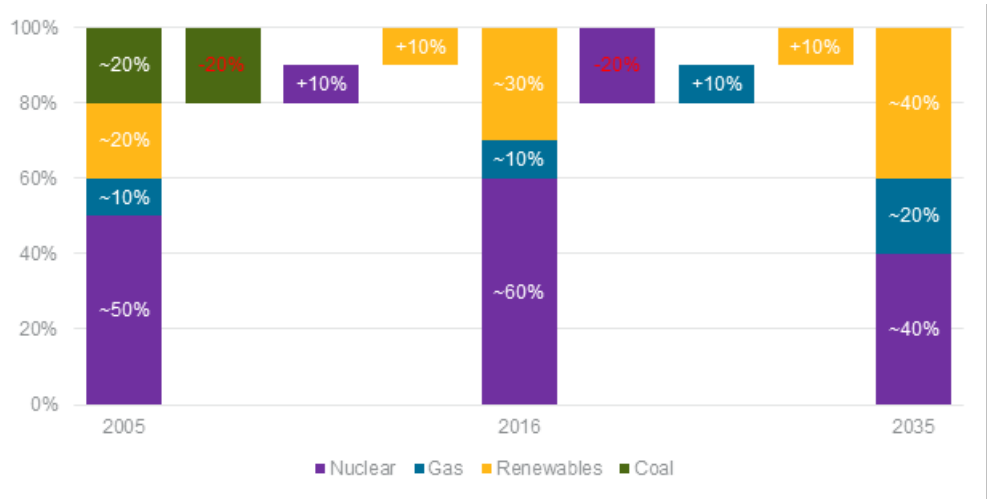

*Source: Independent Electricity System Operator (IESO.ca)*

Ontario achieved this transition largely through new centralised generation resources, such as combined cycle natural gas, nuclear refurbishments, and utility-scale wind. However, Ontario has also experienced an increase in distributed energy resources, such as solar.

Over the long-term (to 2035), the projection for electricity demand growth in Ontario is effectively flat, as growth in end-use consumption is expected to be offset by conservation savings. As a result, Ontario is not anticipating a significant increase in incremental new generation capacity. However, in terms of electricity production, the renewable share of Ontario's total electricity production is forecast to increase by 20 percent between 2005 and 2035 (a doubling in renewable generation). The nuclear share, on the other hand, is forecast to decline by 20 percentage points from today's level. This decrease is due to the retirement of the Pickering nuclear generating station, currently planned for 2024. Of the increase in renewables production, a significant portion is expected to come from centralised, transmission-connected, utility-scale power plants.

The changes in share of electricity production by fuel source are illustrated in Figure 5-2.

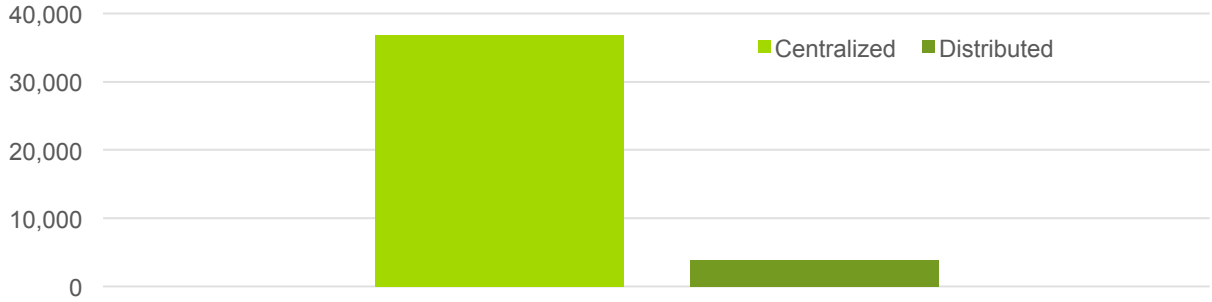
**Figure 5-2. Changes in Share of Electricity Production by Fuel Source: 2005-2035**




*Source: Independent Electricity System Operator*

The figure below shows the forecasted generation capability for the province of in 2025 split between centralised and distributed energy resources.

**Figure 5-8. Comparison of centralised and distributed generation capacity in 2025 (MW)**




*Source: Independent Electricity System Operator*

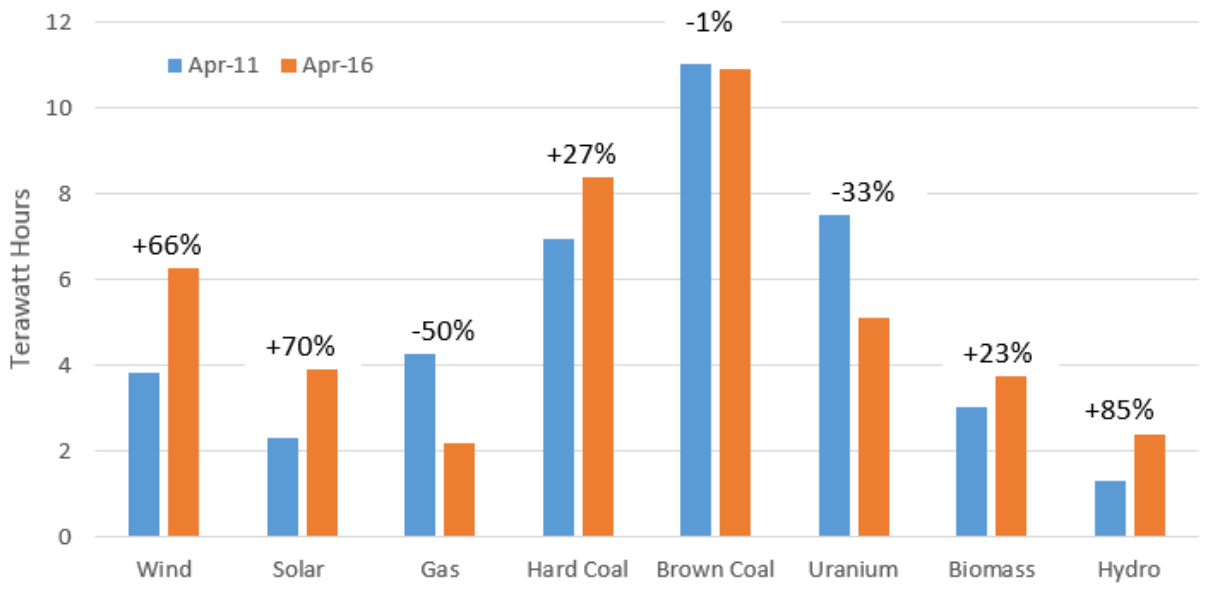
Ontario is largely using policy and regulation as the means to protect and maintain the existing centralised electricity supply system.

## 5.2 Germany

Germany has experienced a profound, decades-long transition of its energy system, called Energiewende. Rooted in the anti-nuclear movement of the 1970s and accelerated by the oil crisis, the Chernobyl nuclear power plant melt down, and most recently the Fukushima nuclear disaster, Germany has experienced a rapid transformation in both the type of power generation and where the power is located. The German Renewable Energy Act (EEG) guarantees full-cost compensation to cover the actual cost of a specific investment in terms of size and technology at a rate guaranteed for 20 years, with declining rates over time. Feed-in tariffs were introduced in order to compensate owners of distributed energy producers, which were reduced as deployment increased and technology costs (particularly solar) were reduced. By 2013, nearly half of the country' installed capacity was distributed generation.

Combined heat and power (CHP) systems, which are thermal power plants that produce both electricity and heat, are highly efficient and can use either fossil fuels or biomass and biogas. CHP systems are widely utilised in industrial applications and in nearby farm units; others feed into large district heating networks that can provide heating for an entire community. More than 30,000 MW of CHP is currently installed in Germany, with as much as 25 percent of thermal power generation coming from CHP by 2020.[9] This is in addition to 40,000 MW of solar and 44,000 MW of wind currently installed. As a result, in April 2016, solar and wind accounted for 9 percent and 15 percent of total electricity generation respectively—up from 5 percent and 9 percent in 2011.

**Figure 5-3. Electricity Generation, Germany: April 2011 vs. April 2016**

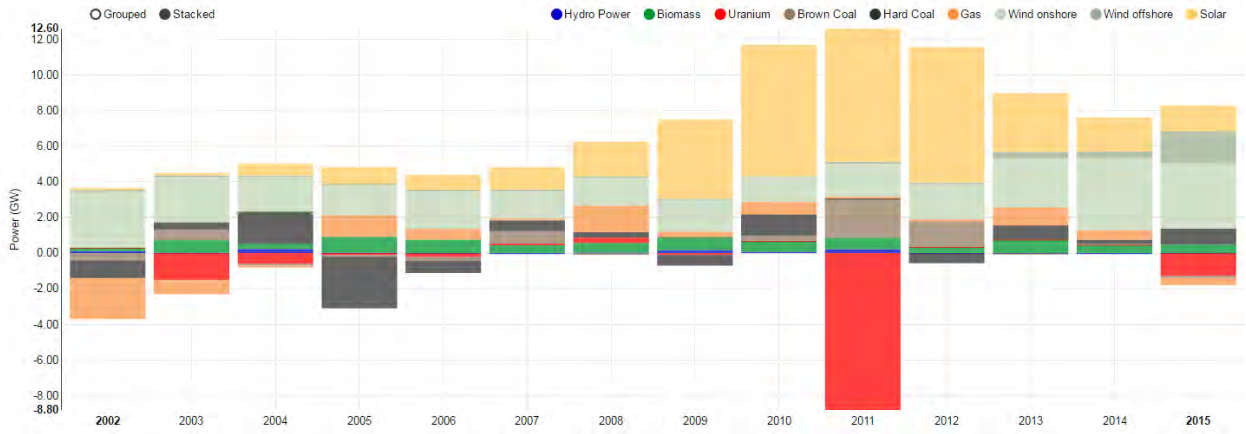



*Source: Navigant Research with data from Fraunhofer*

Centralised coal, nuclear, biomass, gas, and hydro still play critical roles in the German electricity grid, combining for 77 percent of electricity generation in April 2016. However, as the country plans to phase out its remaining nuclear power by 2022, coal will still account for nearly half of all electricity generation. Figure 5-4 shows the net annual electricity generation installed capacity since 2002.

[9] http://www.bmwi.de/BMWi/Redaktion/PDF/E/eckpunkte-papier-strommarkt,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf

**Figure 5-4. Annual Increase and Decrease of Net Installed Electricity Generation Capacity, Germany**




*Source: Fraunhofer*

Policy has been the primary driver of Germany's energy transformation, but the ability of German utilities to export power has been a key enabling factor as well. Germany currently exports power to Denmark, the Netherlands, Poland, Austria, and Switzerland. In 2015, Germany achieved a record foreign trade surplus of CAD$3.07 (€2.07) billion[10] from electricity sales, bringing the total to more than CAD$19.3 (€13) billion during the past 10 years.[11]

In order to reach the highest penetration of renewable energy while displacing nuclear and minimising coal, Germany will also need to integrate storage—though the amount is currently up for debate. Current efforts to integrate storage are taking place at the household and utility-scale level. There are an estimated 35,000 households and commercial operations in Germany that have invested in a solar PV plus battery system. One of Europe's first commercial battery storage systems went online in Germany in September 2014. The 5 MW/5 MWh Li-ion unit participates in the primary frequency regulation market. Additionally, the power station operator STEAG has announced that it will be building six new large-scale 15 MW Li-ion batteries alongside existing power stations that are expected to go online by 2017 to provide primary frequency regulation. Recent studies point to the expansion of the German and inter-European transmission network, demand-side management, and increased flexibility on the generation side as more cost-effective.

[10] CAD$1 = Euro€0.673, Foreign exchange currencies have been converted to CAD using the average exchange rate in the first quarter of 2016

[11] https://www.ise.fraunhofer.de/en/news/news-2016/germanys-electricity-exports-surplus-brings-record-revenue-of-over-two-billion-euros

**Table 5-1. Energy Targets, Germany: 2020, 2050**

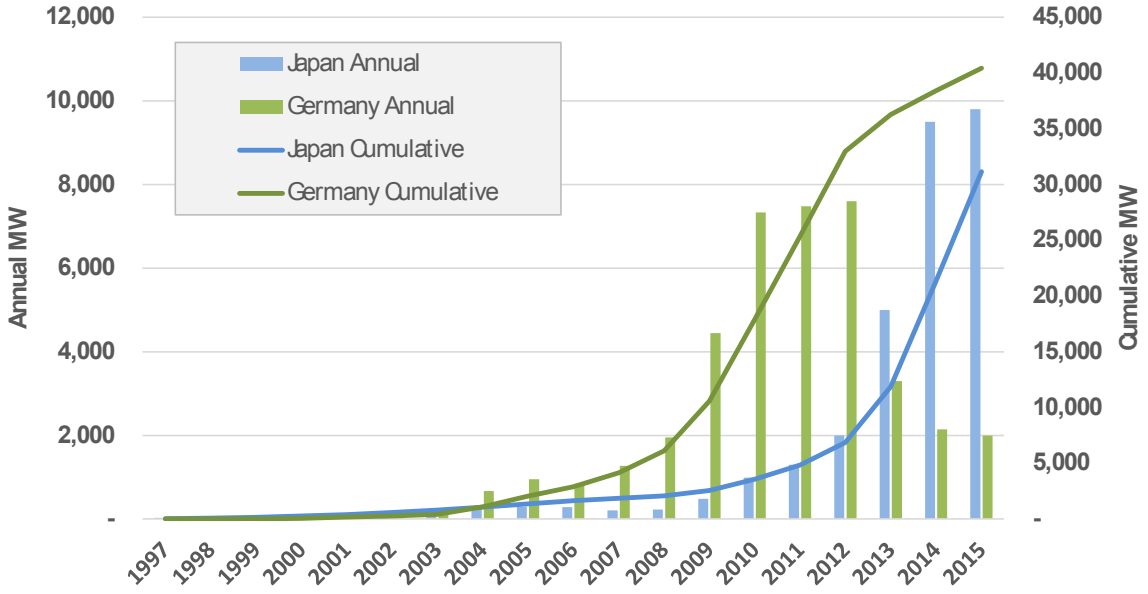
| Target | 2020 | 2050 |
|---|---|---|
| Reduction in GHG emissions (base year 1990) | -40% | -80% to -95% |
| Share of renewable energies in total final energy consumption | 18% | 60% |
| Share of renewable energies in total electricity consumption | 35% | 80% |
| Reduction of primary energy consumption (base year 2008) | -20% | -50% |
| Reduction of electricity consumption (base year 2008) | -10% | -25% |
| Reduction of final energy consumption in the transport sector (base year 2008) | -10% | -40% |

*Source: Navigant*

## 5.3 Japan

Prior to March 11, 2011, as a country with scarce natural resources, Japan's nuclear power program was set to expand from roughly 30 percent of the country' power production to nearly half by 2030. Following the Fukushima nuclear accident, Japan shut down its entire fleet of 48 commercial nuclear reactors in light of safety concerns. Immediately after the shutdown, Japanese utilities relied mostly on importing more LNG and oil. In 2012, following the German model, Japan introduced high-priced feed-in tariffs to promote renewable energy deployment, quickly making it the second largest market for solar PV, after China. Since 2012, 26,000 MW of solar have been installed, with a total of 85,600 MW of renewable energy projects being approved in total—solar PV accounts for the vast majority.

**Figure 5-5. Solar PV Installed Capacity, Japan and Germany: 1997-2015**




*Source: Navigant Research*

Significant debates have taken place in Japan on how much nuclear to reinstate, as the country's 10 main utilities have expressed fear of the fate that met a number of German utilities during its energy transition—mainly the reduction in wholesale rates and declining revenue from retail electricity sales. In response, the government of Prime Minister Shinzo Abe is now advocating for a three-stage reform of the power industry. The centrepiece of the plan is the full liberalisation of the retail electricity market, which

has been largely dominated by regional monopolies over the past 60 years; this is now underway. The plan aims for the establishment of a separate organisation to promote wide-area electrical grid operation, and the separation of power generation and power transmission in 2018 to 2020. As an additional part of this set of reforms, a separate commission drafted medium-term targets for 2030. Under these targets, nuclear power will account for 20 to 22 percent of the nation's electricity supply, while the share of renewable energy will rise to 22 to 24 percent, with the remaining electricity provided from thermal power sources.

Breaking up the 60-year old regional monopolies in Japan signified a major shift and opportunity for the country's energy transition. By the end of October 2015, 778 companies registered as power producers and suppliers in order to sell electricity for commercial consumers, with demand over 0.05 MW. Additionally, 48 companies were approved as retail electricity providers to sell electricity to residential and small business customers.[12] Following rolling brownouts, public energy conservation campaigns, rising electricity costs (CAD$360, US$270/MWh), and an otherwise slowing economy, Japan's customers will be looking for opportunities to reduce electricity payments. While the incumbent utilities have announced to offer lower rates by restarting old coal-fired power plants (cheaper than LNG) and bringing nuclear reactors back online, there is considerable new opportunity for distributed energy providers as well, as evidenced by the enormous pipeline of solar PV projects, including so-called community power systems.

[12] http://www.renewableenergyworld.com/articles/2015/11/japan-s-local-energy-providers-turn-to-distributed-generation.html

# 6. THE RISK OF STRANDED ASSETS

Regulated electric rates are designed to cover a utility's cost of doing business and earn a reasonable return on its capital. The regulatory system relies on the assumption that a sufficient number of ratepayers exist to recover costs over the long term. However, as the level of distributed energy resources rises and markets become more competitive, more customers can defect from the traditional grid and the pool of ratepayers will get smaller over time.

Both public and investor-owned utilities in a centralised system anticipate cost recovery over the lifetime of their investments. Stranded investment in assets occurs when the historic financial obligations of utilities in a regulated market become unrecoverable in a competitive market. When costs can no longer be recovered due to dramatic shifts in the regulatory landscape, the resulting financial burden will have different implications depending on if the utility is publicly owned or investor owned. The risk of stranded centralised generation assets is a major consideration for investors in the sector and should also be a consideration for policy makers.

## 6.1 Public Utility

The degree to which a public utility can recover stranded asset costs is a matter of regulatory and political policy. How these costs will be recovered depends at which point a jurisdiction is in the transition from a centralised to a decentralised system. At one extreme, all customers are off-grid, and the assumption that assets eligible for recovery are used and useful would not apply; thus, any costs related to stranded assets would no longer be recoverable and this would have major implications for taxpayers under a publicly owned utility. The burden of these stranded assets would fall on the taxpayers, as governments would take a loss on the investment. This loss would be felt through either higher taxes or reduced government expenditures. In Ontario, this has happened before, for example with the stranded debt from Ontario Hydro. In this case, a new electricity charge (the debt retirement charge) was enacted by legislation to recover the cost from electricity consumers as opposed to tax payers.

Ontario remains committed to large-scale generation. Nuclear refurbishment has high capital costs that greatly extend the life of these assets. For example, the refurbishment at Ontario Power Generation's (OPG's) Darlington nuclear generating station is an estimated CAD$17 (US$12.8) billion, scheduled to be complete in 2026. This refurbishment will extend the life of the facility by 30 years. This investment is being made under the assumption that over the life of the asset the cost is recoverable from ratepayers, and that the pool of ratepayers will remain large enough to recover these costs over the long term.

## 6.2 Investor-Owned Utility

For an investor-owned utility, stranded asset costs can pose significant risk to investors. Not only is this a risk for current investors who own shares in the utility, but this risk can deter future investors from becoming shareholders. Investors in grid assets will want to ensure their costs are covered and will earn a reasonable return. This implies that rates will rise over time to recover cost. However, if customers are able to defect from the grid, there will be a smaller pool of customers from which to recover costs. Therefore, it may be difficult to raise the needed capital to serve the remaining customers and compensate investors for prior investments on the grid.

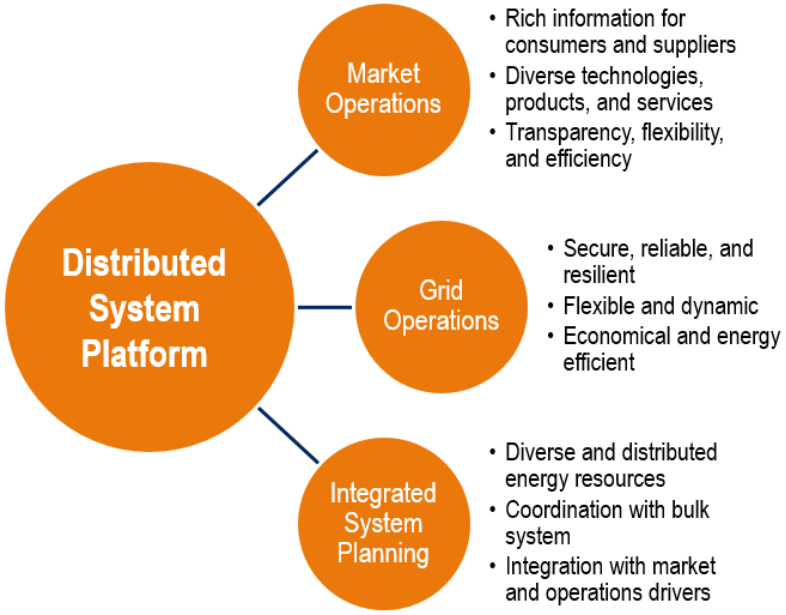
A European example in which traditional power companies have been affected by a surge in renewable energy is Germany. Germany's largest utility, E. ON, posted a record loss for the second year in a row following asset write-downs. The company was forced to write-down the value of its coal- and gas-fired power plants by CAD$12.6 billion (EUR€8.8). Wholesale electricity prices plunged, which has squeezed profit margins for coal- and gas-fired generation.

# 7. INDUSTRY RESPONSE/ADAPTATION

The future role for centralised generation is uncertain. Each jurisdiction is moving at its own pace, and in its own direction.

One framework that is gaining traction in the United States has been outlined by the New York Public Service Commission: utilities would operate as a platform for a variety of existing and new services including market operations, grid operations, and integrated system planning, as illustrated in Figure 7-1. The underlying concept is that utilities would continue to ensure system reliability and procure power at low costs, in large part from centralised resources. However, they would also be empowered to integrate a wider variety of technologies and distributed energy resources alongside the existing centralised generation.

**Figure 7-1. Future Roles for Utilities and Energy Service Providers**




*Source: New York Public Service Commission*

Another way to conceptualise the potential utility of the future is Navigant's Energy Cloud.

Organised to help manage supply and demand across the grid, the Energy Cloud shares many characteristics with cloud computing. As with the IT cloud, these dynamic networks can enhance the efficient allocation of distributed energy resources—including solar, wind, and energy storage systems—across a broad customer base while capitalising on the valuable attributes of centralised generation. Greater stakeholder collaboration and maximising the potential of decentralised power generation are among the Energy Cloud's important benefits, as efforts to modernise an aging grid continue to gain momentum.

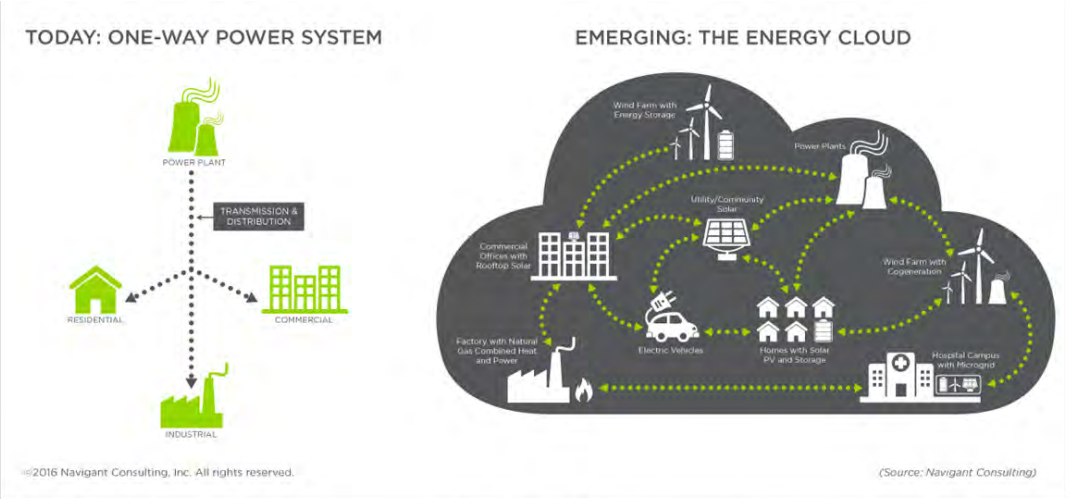
Four key trends underpin the evolution toward the Energy Cloud:

- Increased broad discussion, development, and implementation of new regulations to reduce carbon emission;

- The transition toward an increasingly decentralised grid architecture as a result of a dramatic rise in distributed energy resources and the requirement to integrate efficiently with the current system;
- Greater customer choice—more clients want control over their electricity usage and spend, as well as when and what type of power they buy or, in more extreme cases, the ability to self-generate and sell onsite power back to the grid; and
- Increasing availability of data related to the edge of the electrical grid, enabled by healthy growth in smart grid infrastructure.

The end result of this transformation is a reimagining of how energy is generated, stored, and consumed over the next 20 years (see Figure 7-2).

**Figure 7-2. The Energy Cloud**




- Large, centrally located generation facilities
- Designed for one-way energy flow
- Utility controlled
- Technologically inflexible
- Simple market structures and transactions
- Highly regulated (rate base) and pass through

- Distributed energy resources
- Multiple inputs and users, supporting two-way energy flows
- Digitalization of the electric-mechanical infrastructure: smart grid and behind the meter energy management systems
- Flexible, dynamic, and resilient
- Complex market structures and transactions
- Regulation changing rapidly around renewables, distributed generation (solar, microgrid, storage), net metering etc.

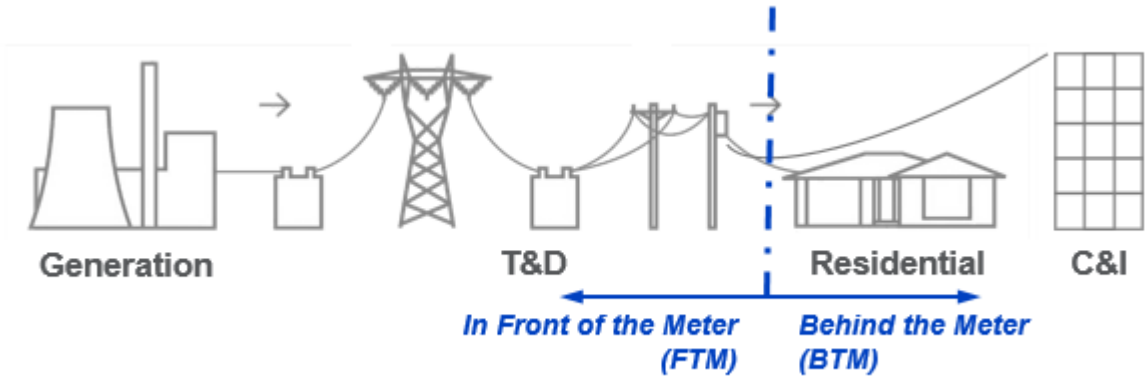
*Source: Navigant*

# PART II: DISTRIBTUED ENERGY RESOURCES

# 1. INRODUCTION

According to recent estimates, roughly CAD$19 to $24 (US$14 to $18) billions of electricity sales revenue is lost annually due to transmission and distribution (T&D) line losses worldwide. This reality, combined with recent events highlighting the fragility of the centralised electricity network, has generated unprecedented interest in the development of distributed energy resources (DER) to both improve grid resiliency and avoid large centralised generation capital expenditures. Encompassing a broad set of solutions that include systems and technologies designed to operate closer to customers on the electricity grid, the proliferation of DER around the world has led to significant reduction in the deployed cost of these technologies, and begun to have a significant, and at times controversial, impact on the electricity grid and industry.

**Figure 1-1. Behind the Meter**



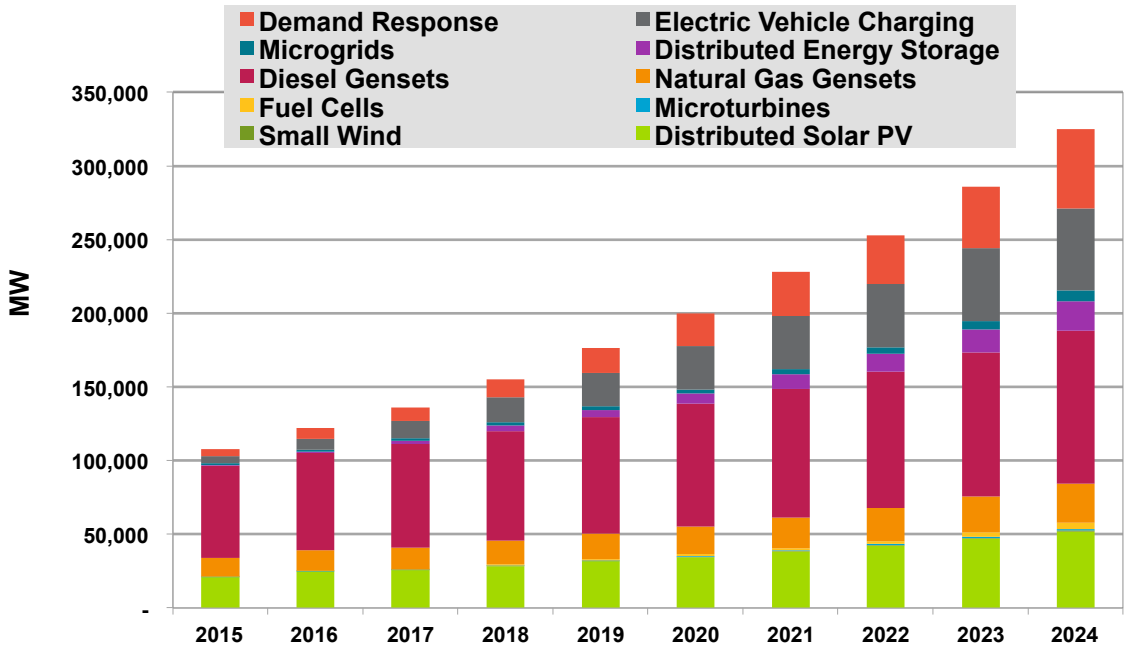

*Sources: Navigant, Australian Government Department of Industry, Innovation and Science*

# 2. TECHNOLOGIES

DER includes technologies with unique characteristics that can act as both generation and/or load control on the grid. Despite the differing operating characteristics, these technologies all represent new and dynamic resources that can challenge the prevailing business models and standard operating procedures in the industry. The technologies covered in this report are generally installed behind-the-meter (BTM) at customer facilities and may be owned by customers themselves, third-party vendors, or utilities. While these resources are primarily designed to provide value and benefits for the end users hosting them, their integration into the grid can have significant impacts for utilities and grid operators.

A forecast of various DER technologies looking out to 2024 shows strong growth in most categories (see Figure 2-1).

**Figure 2-1. Annual Installed DER Power Capacity by Technology, World Markets: 2015-2024**




*Source: Navigant Research*

Table 2-1 summarises DER technology characteristics and is followed by more detailed descriptions of each technology.

**Table 2-1. DER Technology Characteristics**

| Technology | Cost Summary | Installed Cost ($/kW) | Pro | Con | Emissions | Integration Challenges |
|---|---|---|---|---|---|---|
| Demand Response | Often least-cost option to obtain MW | CAD $67-$267 (US$50-$200) | Quick to deploy | Customers may choose to opt out | None, unless using backup generator | Requires adequate control equipment and, communication and visibility to system operator |

| Technology | Cost Summary | Installed Cost ($/kW) | Pro | Con | Emissions | Integration Challenges |
|---|---|---|---|---|---|---|
| Energy Storage | Most expensive option currently, though strong cost reduction trajectory | CAD$2,000-$5,333 (US$1,500-$4,000) | Maximum flexibility for loads | Thus far unproven at mass market scale | None, unless charged with electricity generated from carbon emitting resources | Requires proper communication and interconnection equipment |
| Solar PV | Dramatic reductions in costs recently; grid parity in some areas | CAD$2,667-$6,667 (US$2,000-$5,000) | Long system life with little degradation; increasing efficiencies | Not suitable for all homes/buildings | None | Higher penetration leading to push back from utilities concerned with overloading circuits, revenue loss |
| Combined Heat and Power | High capital costs but short paybacks in optimal situations (high heating/cooling loads) | CAD$1600-$6,667 (US$1,200-$5,000) | Provides multiple outputs with one input | Financing can be difficult to obtain, not suitable for all end users | Some if fuelled by natural gas; none if fuelled by hydrogen | Need proper interconnection process |
| Electric Vehicles | Favourable economics from total cost of ownership today; scaling rapidly | CAD$153-$1733 (US$115-$1,300) | Take advantage of assets deployed for other purposes | Requires dramatic increase from current adoption in order to have a meaningful grid impact | Grid emissions are lower compared to gas-powered engines | Need adequate charging and vehicle to grid infrastructure |

*Source: Compiled by Navigant*

## 2.1 Demand Response

Demand response (DR) is any action taken to change—most often to reduce, but in some cases to increase—customer electricity demand based on a signal or notification from the grid or a financial incentive from a utility or grid operator. These signals may initiate within the customer site to manage internal operations or costs, or may come from the electric grid to address system constraints or price spikes. Most large commercial and industrial (C&I) customers are familiar with and have taken advantage of DR opportunities available to them, but the mass market (residential and small commercial) has more room for growth through customer education and engagement. Direct load control programs for residential and C&I customers are available in a number of jurisdictions and are increasing in prevalence.

## 2.2 Solar Photovoltaic

Distributed solar is defined as systems that are installed onsite or close to the customer/end user. These systems are typically less than 1 MW in capacity and present perhaps the most significant challenge to incumbent utility business models. Due to its close proximity to load, distributed solar reduces the need to

build new transmission capacity and reduces transmission line losses. Utilities will need to ensure that power from solar and other distributed generation technologies matches the voltage, frequency, and power quality of the grid. This will become increasingly important as markets grow and community-based projects come online, requiring the use of smart grid technologies and other DER to effectively manage the load supply and demand balance.

## 2.3 Energy Storage

Distributed energy storage systems (DESSs) include systems located BTM at customer facilities as well as community energy storage. Community energy storage, which refers to utility-owned storage systems at the distribution transformer or downstream feeder level, can help resolve harmonics and voltage issues caused by energy pushed in the opposite direction by any DER. Intermittent resources such as solar and wind, especially at the distributed scale, create challenges for the traditional centralised grid that was built for one-directional power flow. DESSs can provide valuable services to a grid that is working to integrate large amounts of renewable energy. These services can be provided through applications that include but are not limited to bulk load shifting, peak shaving, demand response, and operating reserves. While there are numerous services that DESSs can provide, to date most are designed to help end-use customers control their energy costs and provide protection against power outages.

## 2.4 Combined Heat and Power

Sometimes referred to as cogeneration, combined heat and power (CHP) is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single integrated system. Although the high upfront cost of CHP systems and the challenge of finding suitable use for the heat generated are key barriers, relatively short payback periods have allowed many businesses to invest in these technologies. As an integrated system, CHP deployments are not dependent on a single breakthrough technology, making them widely available for a range of applications. CHP can be composed of numerous technologies such as gas or steam turbines, reciprocating engines, micro turbines, and fuel cells.

## 2.5 Electric Vehicles

Electric vehicles (EVs) are expected to play an important role in the evolving DER mix due to their ability to provide various grid services through vehicle-to-grid integration (VGI). Unmanaged plug-in EV (PEV) charging can significantly increase load and also strain local distribution transformers. Managed charging can not only reduce this risk but can also be leveraged to utilise battery power capacity to make the grid more efficient and reduce costs to consumers.

VGI requires the participating PEV to communicate with and allow charging to be managed by the grid operator when plugged in. In return, the PEV owner is financially compensated. VGI communications for charge management through one-way power flow from the grid to the battery pack allows a grid operator to modulate the battery charging rate for participation in DR programs and even regulation services. Vehicle-to-grid (V2G) power transfer, on the other hand, involves bidirectional power flow between the vehicle's battery pack and the grid. While in theory net beneficial, there are concerns that V2G will contribute to premature battery degradation, as the battery will be subjected to charge and discharge cycles outside the requirement for actual driving needs. This could limit the acceptance of V2G technology by EV owners.

## 2.6 Other: Micro turbines, Fuel Cells

Micro turbines are small combustion turbines with outputs of 25 – 500 kW. Micro turbines are currently expensive, at CAD$4,000(US$3,000/kW) installed. On a distributed scale, this high capital cost is likely to limit its adoption, and the technology is unlikely to see substantial cost reductions over the next decade. However, micro turbines can be leveraged to save customer energy costs, as they can be used to participate in DR and shave peak demand, contributing to attractive savings. In other cases, opportunity fuels such as landfill gas or flare gas from a wellhead or refinery may provide a free fuel source.

A stationary fuel cell is any product that is designed to be installed in a permanent location and cannot be physically carried around. One application is prime power, where the fuel cell is used for electricity or power and heat, usually at a scale of 200 kW and higher. Other applications include micro CHP, which uses a relatively small fuel cell (under 10 kW) in residential applications or small business settings, and backup or uninterruptible power, where a fuel cell (under 10 kW) is used to provide power when the grid is down.

# 3. MARKET ISSUES

A plethora of technology, policy, economic, and customer considerations serve as drivers, enablers, and barriers for DER adoption. It is not just a technical problem that needs to be solved, but rather a series of enabling technologies and regulatory reactions that interplay with each other. Sometimes it can be a moving target depending on which is advancing faster—the technology or the policy. Business models and technology will need to be flexible to adapt to the changing landscape.

## 3.1 Drivers

Economics, supported by targeted policies, are currently the largest driver for DER. Reliability and environmental concerns are secondary but growing influencers of DER development.

### *3.1.1 Cost Savings*

Energy-related (heating, cooling, lighting, etc.) costs are typically one of the largest expenses for commercial buildings, and one of the most difficult to predict. Although the capital expenditure requirements for a DER system may be high, the operating costs of a building or institution without a DER system are often incentive enough to justify the initial upfront cost. Generally, the higher the operating costs are for a given application, the more attractive the return on investment is for a DER installation. The payback period varies depending on the jurisdiction, technology and application, but most DER developers aim to deliver a five to seven-year payback period. Generally, larger installations will achieve shorter payback periods due to economies of scale. Savings can be reinvested into facility improvements or applied directly to the bottom line.

For residential consumers, energy does not encompass as much of their budget as it does for businesses, but many people are still interested in reducing their spending if a cost-effective option exists. Many DER systems have extensive paybacks under current pricing structures, but subsidies and tax breaks can make them worthwhile in high energy cost areas. With DER costs expected to decline over the next several years and grid supplied electricity costs expected to increase, DER will become economic for more residences.

### *3.1.2 Policy*

DER adoption would not be nearly as advanced as it is today without a variety of policy mechanisms at the national and sub-national levels. Different jurisdictions have devised different schemes to compensate customers for the positive externalities that DER offer, but they all share the goal of making these products more affordable for a larger part of the population.

**Net Metering**
For electric customers that generate their own electricity, net metering allows for the flow of electricity both to and from the customer—typically through a single, bidirectional meter. With net metering, electricity from the customer flows back to the grid when generation exceeds use, which has the effect of offsetting electricity consumed by the customer at a different time. Basically, the customer uses excess generation to offset electricity that the customer otherwise would have to purchase at the utility's full retail rate. In the United States, the Energy Policy Act of 2005 requires all public electric utilities to offer net metering to their customers. However, the rates and rules vary depending on state laws and utility policies. Currently, net metering is offered in 47 states.

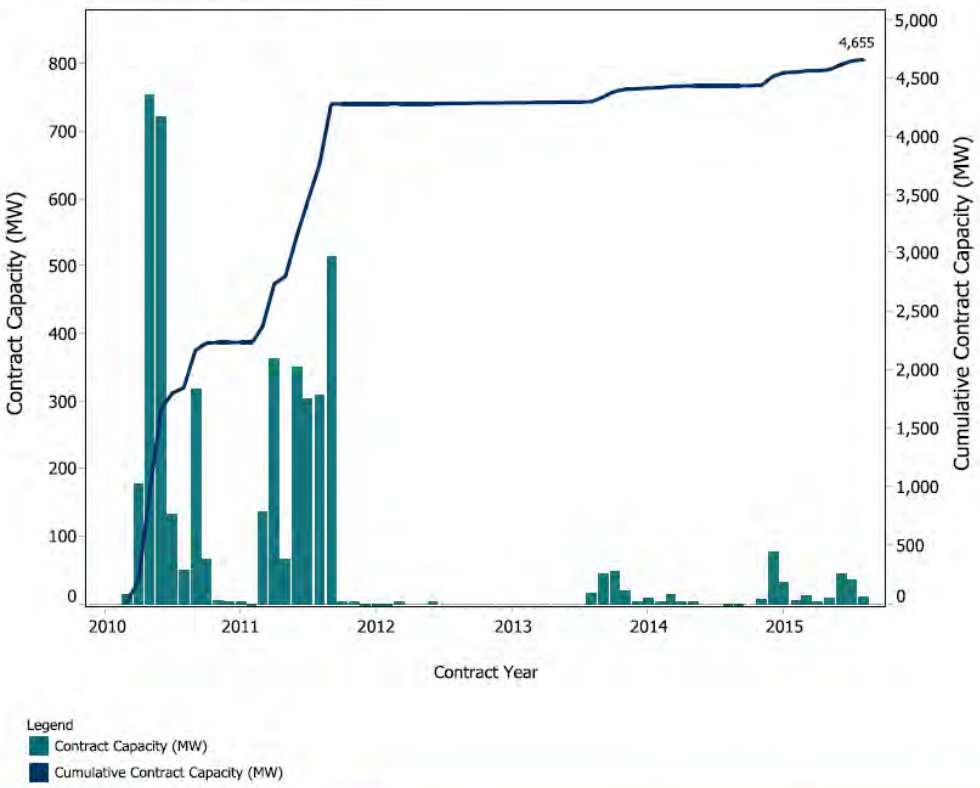
Most countries with high concentrations of residential PV have favourable net metering policies. Some countries with net metering policies are Barbados, Belgium, Denmark, Italy, Brazil, Mexico, Pakistan, and the Philippines.

**Feed-In Tariffs**

Feed-in tariffs (FITs) have been a major demand driver for the global distributed solar PV market. By some estimates, they are responsible for 75 percent of solar and 45 percent of wind development globally. The term feed-in tariff originated in Europe and refers to the renewable producer's right to interconnect to the electric grid. The tariff is the rate at which the producer is paid for the power it feeds into the grid. Most FITs involve a long-term contract between the asset owner and the utility—usually 15 to 20 years. The FIT is essentially a guaranteed rate of return on the renewable energy investment, though it can contribute to an overheated market that can jeopardise long-term deployment.

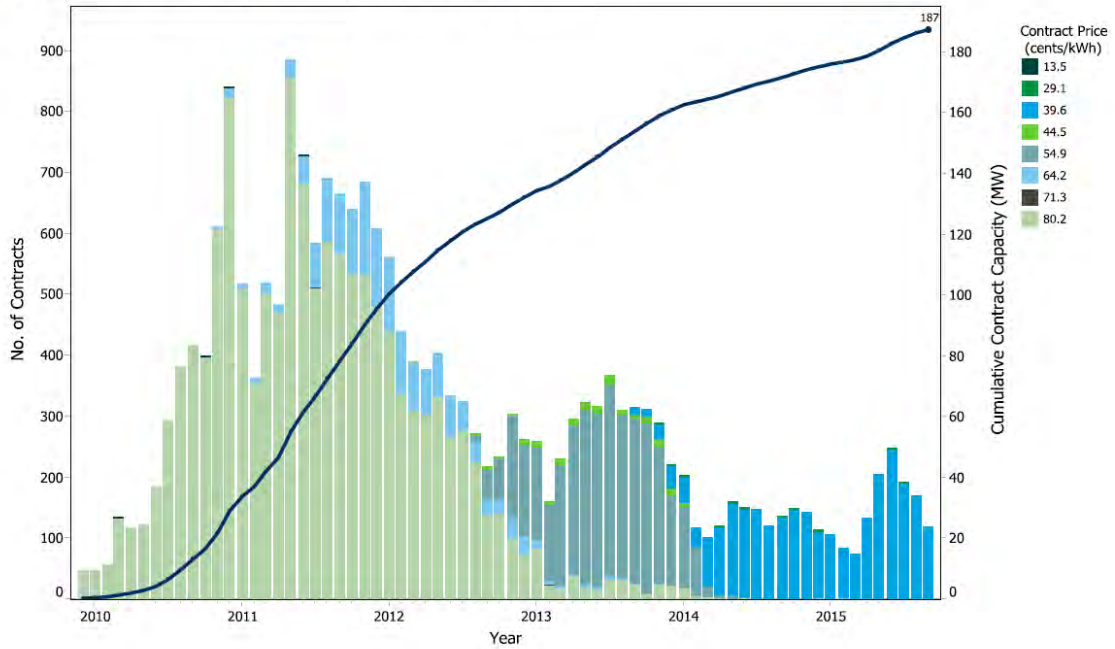
In 2009, Ontario introduced North America's first comprehensive FIT—under the *Green Energy and Economy Act, 2009*— which is administered by the Independent Electricity System Operator. Under the FIT and microFIT programs, generators are paid a guaranteed price for all the electricity they produce for at least 20 years. The FIT program is for projects between 10 and 500 kW, and microFIT is for projects under 10 kW. The microFIT program is designed to encourage homeowners, farmers, and small business owners to invest in distributed renewable energy. As of 2015, Ontario offers up to CAD$0.38/kWh(US$0.29/kWh) for rooftop projects of up to 10 kW, down to CAD$0.27/kWh (US$ 0.21/kWh) for ground-mounted projects of between 10 kW and 500 kW of capacity. The program has resulted in nearly 5,000 MW of distributed solar PV installations through 2015 (see Figure 3-1 and Figure 3-2).

**Figure 3-1. Ontario FIT Procurement by Year**




*Source: IESO*

**Figure 3-2. Number of microFIT Contracts by Price and Capacity Growth**




*Source: IESO*

**Tax Incentives**

The energy Investment Tax Credit (ITC) in the U.S. has played a key role in improving the economics of renewable generation (particularly wind and solar) at all levels, which has led to dramatic growth of these resources in recent years. The ITC provides varying incentives for different DER including solar, fuel cells, small wind turbines, geothermal systems, and micro turbines. While the U.S. solar ITC is scheduled to step down annually until reaching 10 percent for utility-scale power plants and zero for distributed systems—down from the current 30 percent—these industries have already benefited greatly from the program. Another key U.S. federal incentive is tax credits available for EV purchases. This CAD$10,000(US$7,500) credit has greatly improved the economics of EV ownership and has resulted in a growing market for those vehicles; many states also offer incentives for EVs and charging infrastructure.

**Renewable Energy Certificates**

Renewable Energy Certificates (RECs), also referred to as green tags or green credits, are tradable, non-tangible energy commodities that represent 1 MWh of electricity generated from a renewable source. The renewable energy is generated and added to the grid (i.e., sold). A REC is issued for the energy and then sold or traded in the same or a separate transaction, allowing the buyer to claim to have purchased renewable energy. It is essentially a production incentive for the owner of the renewable energy generation asset and a proof of purchase of renewable energy for the owner of the REC.

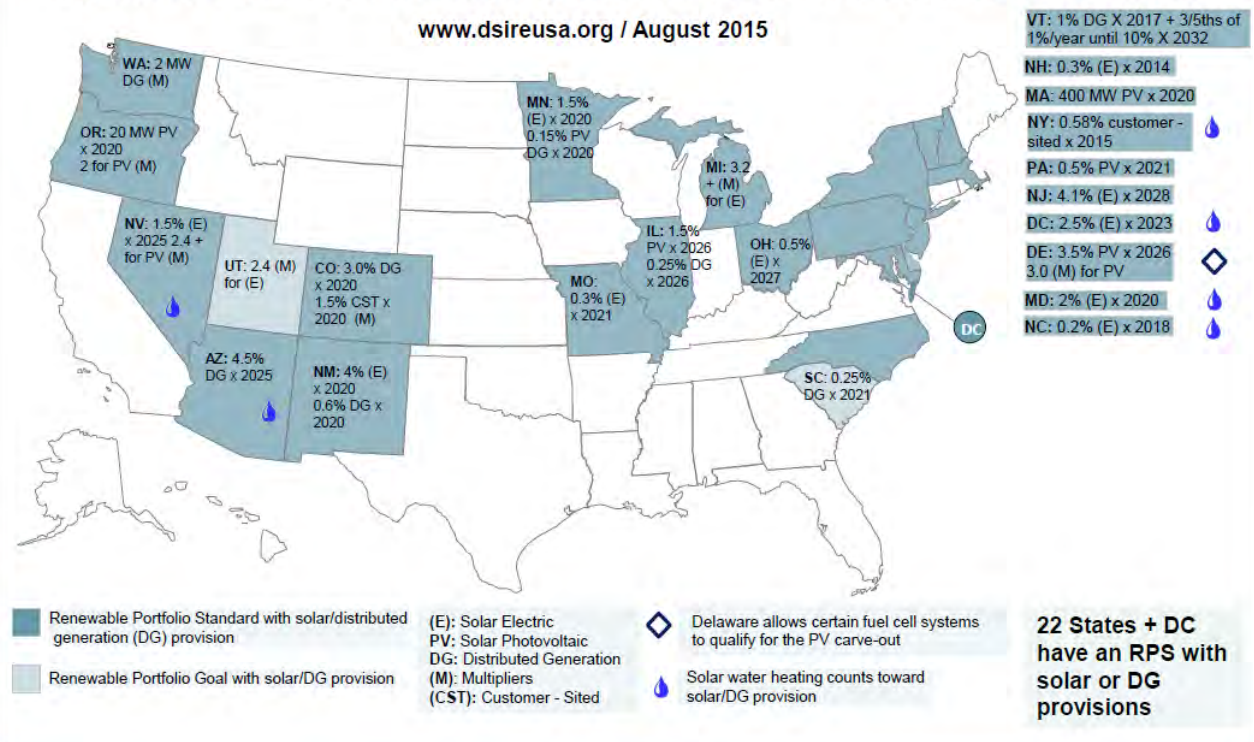
RECs are traded in either compliance or voluntary markets in the United States and Europe. In Europe, Italy, Poland, and the United Kingdom were the main supporters of REC policies, but only Poland maintains it. In the U.S., RECs remain a demand driver of renewable capacity build-out, although generally at the utility as opposed to distributed scale.

**DG Carve-Outs**

While there is no national target for renewable energy deployments in either the United States or Canada, there are currently 30 states in the United States that have Renewable Portfolio Standards (RPSs) that

mandate targets for renewable generation on the grid, and 22 of those states currently have specific solar or DG provisions in their RPS program (see Figure 3-3).

**Figure 3-3. Renewable Portfolio Standards with Solar or DG Provisions**




*Source: Database of State Incentives for Renewables and Efficiency*

### *3.1.3 Self-Sufficiency/Security of Supply*

Energy security refers to a desire to ensure satisfactory energy supplies over time. It can apply to utilities and organisations such as businesses (C&I), institutions (hospitals and universities), and residential customers. Energy is a key input into crucial economic activities and mission-critical operations. End users and grid operators are often willing to invest in technology that will guarantee energy supplies even in periods of scarcity such as natural disasters, infrastructure decay, or cyber security threats.

For small and midsize businesses, electricity failures can bring business to a halt, cutting into profits and potentially alienating customers. Organisations that have 24-hour operations or operations that deliver critical services (e.g., hospitals) are particularly susceptible to lapses in power. These types of organisations are often good candidates for DER. An Electric Power Research Institute study in the United States shows that a business can lose significant revenue due to just 1 hour of power loss. As a result, these sensitive customers are willing to invest in DER, in particular BTM resources, to provide protection and security against such instances.

**Table 3-1. Estimated Losses per Hour of Grid Failure**

| Operations/Industry | Units | Estimated Losses |
|---|---|---|
| Cellular Communications | ($/hour) | CAD$54,667(US$41,000) |
| Telephone Ticket Sales | ($/hour) | CAD$96,000(US$72,000) |
| Airline Reservations | ($/hour) | CAD$120,000(US$90,000) |
| Credit Card Operations | ($/hour) | CAD$3,440,000(US$2,580,000) |
| Brokerage Operations | ($/hour) | CAD$8,640,000(US$6,480,000) |

*Source: Electric Power Research Institute*

### *3.1.4 Environment and Climate Change*

The majority of carbon dioxide emissions are attributable to sectors that require or generate stationary power. The stationary power sector offers huge potential for climate change mitigation, and DER is well positioned to contribute to energy efficiency goals by reducing dependence on electricity and heating systems. As policymakers around the world continue to target emissions in this sector, this increased scrutiny is leading to policies that encourage DER by forcing building owners to internalise the cost of emissions.

A specific example of emissions regulations that will affect DER is the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan. In June 2014, the EPA released its draft regulations on carbon emissions from existing power plants, known as 111(d), or the Clean Power Plan. In a departure from prior power plant regulations, this plan will allow states to use outside-the-fence measures in their compliance plans to meet the emissions reduction targets. Options like natural gas replacements for coal, nuclear power, renewable energy, and energy efficiency can offset emissions. From an emissions efficiency perspective, DER is certainly an option with positive economic value.

The 2015 United Nations Climate Change Conference was held in Paris, France. This was the 21st yearly session of the Conference of the Parties, COP21. At the meeting, Canada made a commitment to working with international partners to reach a global agreement that leads to a low-carbon economy. Canada is also committed to supporting the poorest and most vulnerable countries to adapt to the adverse effects of climate change. The government of Canada is making significant investments in green infrastructure and clean technologies. These include:

- Endow a CAD$2.67(US$2) billion Low Carbon Economy Trust to fund projects that reduce carbon.
- Fulfil Canada's G20 commitment and phase out subsidies for the fossil fuel industry.
- Work with the provinces and territories to develop a Canadian Energy Strategy to protect Canada's energy security, encourage energy conservation, and bring cleaner renewable energy into the electricity grid.

Representing Ontario, premiere Kathleen Wynn took part in COP21 to promote Ontario's role in fighting climate change. At the conference, the premiere signed a memorandum of understanding on cooperation in the area of climate change with Manitoba and Quebec. This memorandum facilitates the three province's intent to link cap and trade programs in Ontario, Quebec, and Manitoba under the Western Climate Initiative. Also at the conference, the Wynne government announced Ontario will invest CAD$26.7(US$20) million from the Ontario Green Investment Fund to build EV charging stations across the province.

## 3.2 Enablers

Aside from the direct drivers listed above, there are a number of resulting and complementary enabling technologies and trends that further encourage DER development.

### *3.2.1 New Business Models*

As DER hardware (e.g. modules, racking, inverters, etc.) has become increasingly commoditised, opportunities for extracting margin in a highly competitive industry are scarce. However, new business models, such as lease, yieldcos, green bonds, and others, have both reduced barriers for customers and increased potential for profits—while also increasing the overall market for DER.

Solar developers typically have one of five standard business models: power purchase agreements (PPAs), leases, cash purchases (host-ownership with cash/self-financing), and financed (loan), and rate base as discussed in Table 3-2.

**Table 3-2. Solar Business Models**

| Type | System Ownership | Notes | Companies |
|---|---|---|---|
| PPA | Third-party owner (TPO) | Developer owns the system; a per kWh rate is paid by the host for each kWh produced. | SolarCity |
| Lease | Third-party owner (TPO) | Operating lease, potentially with service and performance guarantees. | SolarCity, Vivant, SunRun |
| Cash Purchase | Host owned | System is sold directly to the customer. | Direct |
| Financed (Loan) | Host owned | System is leased for eventual ownership. Potential service and performance guarantees. | Direct |
| Rate Base | Utility owned | Utility builds, owns and operates the DER resource and part of its regulated asset base. | |

*Source: Navigant*

Third-party ownership (TPO) may be peaking in the wake of a revived movement to own solar as costs have come down and paybacks are shorter. TPO providers have responded by offering loans whereby the customer can take advantage of tax credits and other incentives while paying back the loan.

Storage business models are still evolving, with the most typical options shown in Table 3-3.

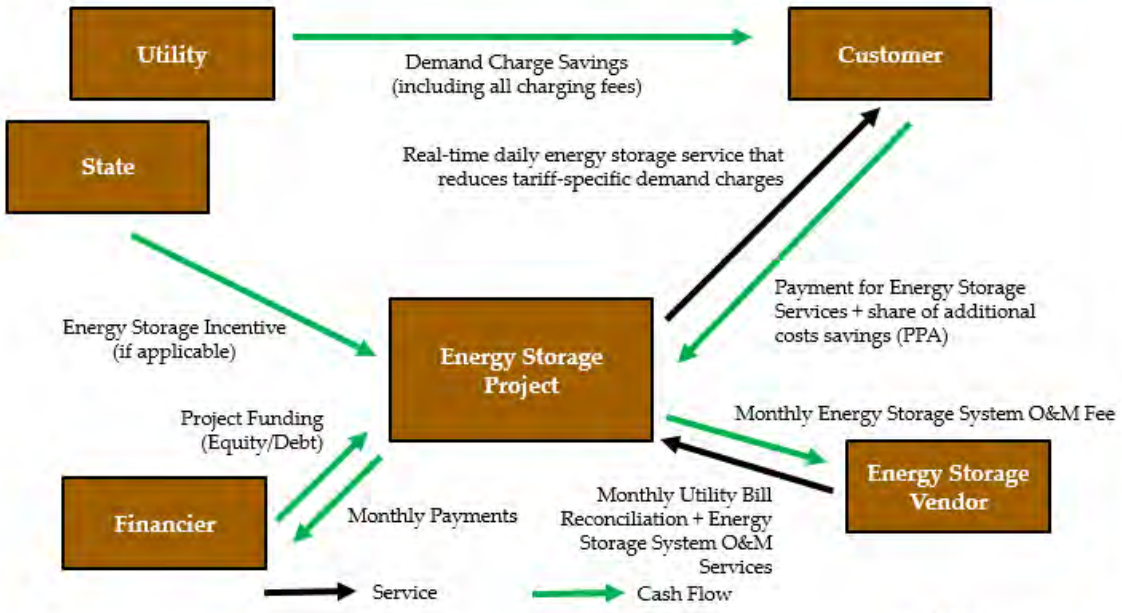
**Table 3-3. Storage Business Models**

| Type | System Ownership | Notes | Companies |
|---|---|---|---|
| Shared Savings Model | TPO | Vendor owns, operates, and maintains energy storage system on customer premises. Customer and vendor share in cost savings. Battery performance guarantee/warranty is key | Green Charge Networks, CODA Energy |
| Sale/Lease + Host Control | Host Owned | System is leased for eventual ownership. Potential service and performance guarantees | Sharp, Stem, ZBB Energy, SolarCity |
| Utility Procurements | TPO<br>Utility-controlled | Utilities procure and will operate aggregated DESSs located BTM through a contract with vendor/service provider | Advanced Microgrid Solutions, Stem |
| Sale/Lease + Utility Tariff Rate | Host Owned<br>Utility-controlled | Utilities offer special tariffs and pay for systems if allowed to control them and able to use them for investment deferrals and during emergencies | Tesla, Sunverge, San Diego Gas and Electric |

*Source: Navigant*

In the third-party energy storage system ownership model, the system is financed over 10 years with the customer paying a fee and sharing in savings with the vendor.

**Figure 3-4. Shared Savings Model**




*Source: Navigant*

Solar plus storage (solar + storage) installations are more complex because of the need to install a new electrical panel for the critical electrical loads, so the solar + storage plus critical loads can operate independently of the grid in a blackout. This landscape is expected to evolve quickly over the next two to four years as technology develops and costs decline. The solar + storage options currently available or under discussion include a variety of strategies, as seen in Table 3-4.

**Table 3-4. Solar and Storage Business Models**

| Type | System Ownership | Notes | Companies |
|---|---|---|---|
| Cash Purchase | Host Owned | System is sold directly to the customer. | |
| Financed (Loan) | Host Owned | System is leased for eventual ownership. Potential service and performance guarantees. | |
| Lease | TPO | Operating lease, potentially with service and performance guarantees. | SolarCity |

*Source: Navigant*

### *3.2.2 Competitive Retailer Energy Suppliers*

Outside of the strict regulated utility construct, competitive retail energy suppliers are also starting to offer DER options to their electric and gas commodity customers in order to provide more value and increase customer loyalty. The most striking examples are in Texas, where all customers must choose a competitive supplier since utilities are not allowed to do so. Many retailers are partnering with technology

vendors (Direct Energy and NRG with Nest; Constellation with Stem) to give customers free or discounted devices to help them save on their bills. This trend may become particularly popular in the United Kingdom, where retailers have more of the responsibility for energy reliability requirements than is the case in the United States.

### *3.2.3 Advanced Metering Infrastructure*

AMI has the ability to meter production and consumption in hourly or more granular intervals, and could therefore be employed in DER implementation. The growing prevalence of AMI has provided valuable data to players in the energy industry. The information that comes from the analysis of AMI data can be incredibly useful in fostering DER. Utilities can use AMI data to verify load shed or generation, initiate dynamic pricing rates, and provide customers with information and feedback on consumption. The full value of DER rests upon the ability to measure time-differentiated production and consumption in a timely manner that is visible to the system operator.

### *3.2.4 Dynamic Rate Structures*

In the electricity industry, the concept of dynamic pricing for mass market customers is fairly recent aside from time-of-use (TOU) rates. TOU, which offers set prices for fixed on- and off-peak periods that do not vary during the tariff period, have existed for decades. They are simple tools to discourage on-peak and encourage off-peak energy consumption. Rates that are indexed to real-time wholesale energy prices have been around for large C&I customers since deregulation in the mid-1990s, though few currently take advantage of them. With the proliferation of advanced meters that can record usage at small intervals, more dynamic types of pricing can be applied down to the residential level.

In the case of commercial customers, the primary function of energy storage is energy cost management. Thus, the most important market condition for this application is the rate structure for C&I customers. The least conducive is a flat rate electricity tariff. The most conducive rate structure includes demand charges and TOU pricing. The bulk of the residential market is energy storage tied to solar, particularly in markets where solar FIT rates are lower than electricity rates, making it less attractive to export solar energy to the grid. In rare cases, residential energy storage is being purchased on its own, but this scenario requires TOU pricing and a high willingness to pay for reliability or backup systems on the part of the residential customer.

EVs have a similar effect on the grid and on customer usage as stationary energy storage. As the use of EVs expands, so does the potential for large load spikes during peak charging times. By using price signals, a utility can incentivise its customers to charge at off-peak times, causing a smoothing out of the load curve. For example, in Ontario’s recent climate change action plan, there is a call for free off-peak charging of EVs.

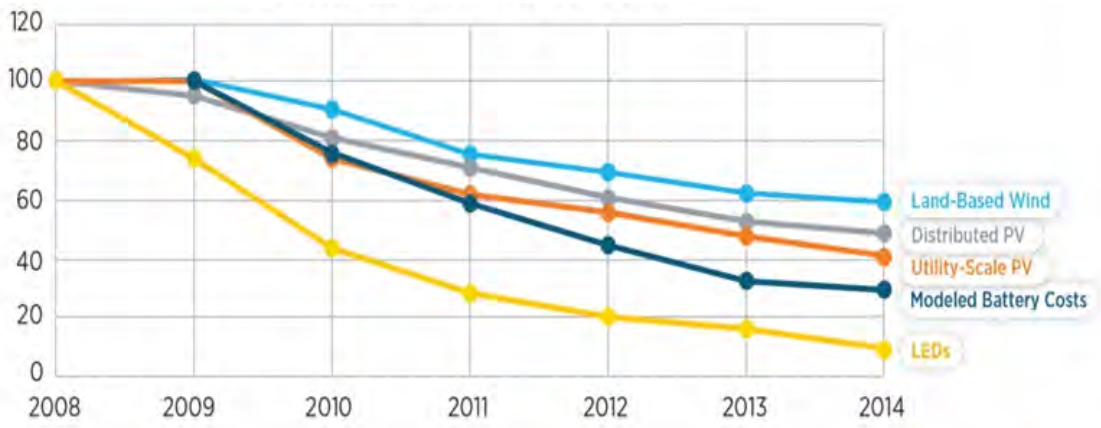
# 4. BARRIERS

The picture is not all rosy for DER growth, as a number of barriers to widespread deployment still exist. Some of these factors are simply the flip-side of the drivers, like cost and policy, while others have to do with the existing energy industry structure and infrastructure.

## 4.1 Cost

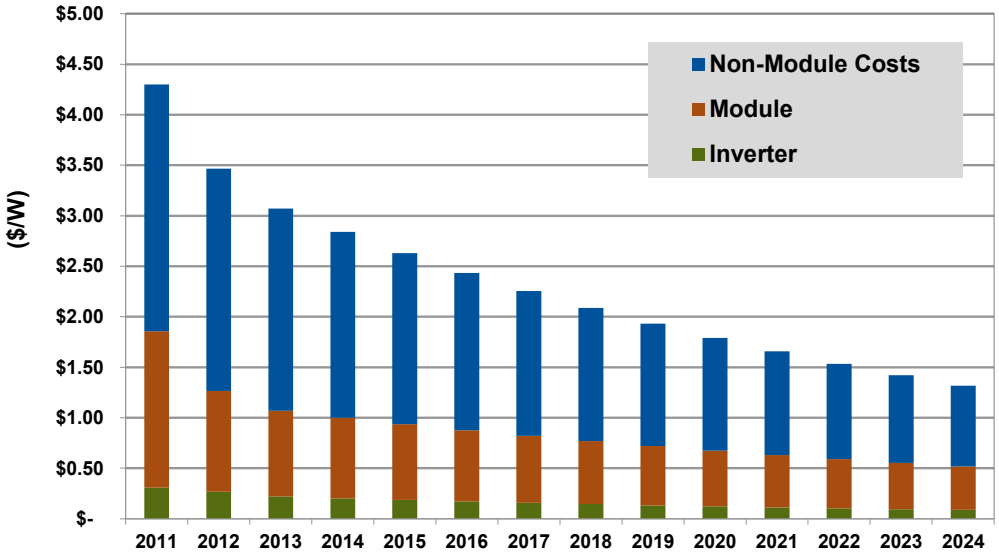
In general, system costs have come down for renewables and DER specifically, as shown in Figure 4-1, Figure 4-2, and Figure 4-3.

**Figure 4-1. Indexed Cost Reductions Since 2008**



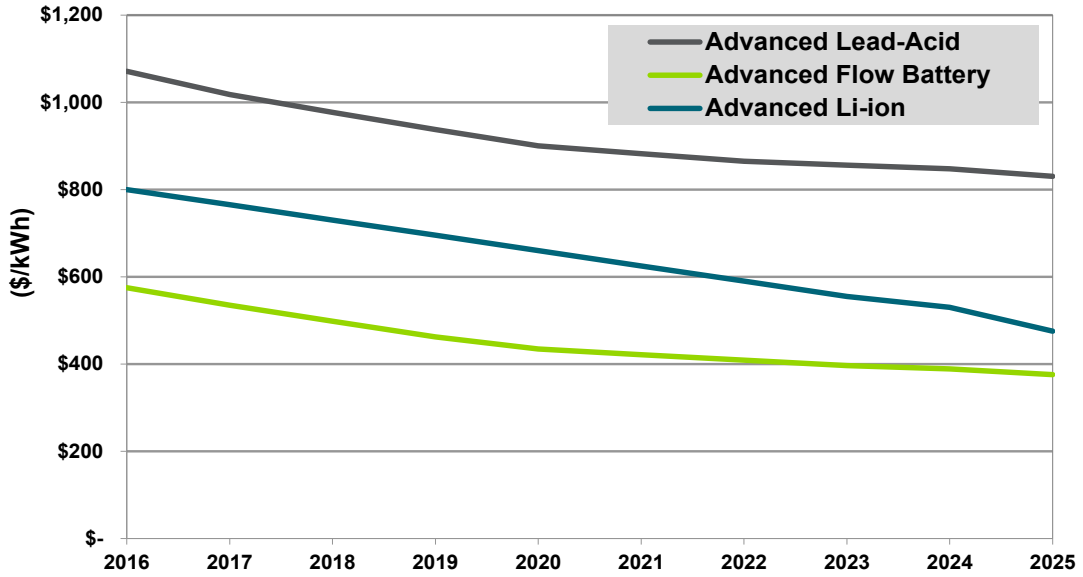

*Source: U.S. Department of Energy*

**Figure 4-2. Distributed Solar PV Installed System Prices (Non-Weighted Average) by Component, World Markets: 2011-2024**




*Source: Navigant Research*

**Figure 4-3. Average C&I Energy Storage System Installed Costs by Technology, World Markets: 2016-2025**




*Source: Navigant*

While unsubsidised utility-scale energy projects have to compete with wholesale electricity prices to be attractive, DER competes with (considerably higher) retail prices. DER offers the promise of reduced operating costs in exchange for an upfront capital investment. However, the technologies for DER vary greatly in terms of installed cost per kilowatt. DER upfront costs remain one of the main barriers to increased adoption among commercial and residential end users. Although business buyers typically operate on longer-term budgets than households and will often plan for purchases well in advance, interest in DER can still wax and wane depending on movements in the price of electricity and other fuel sources.

## 4.2 Policy/Regulations

While net metering has significantly advanced DER adoption, it has received some pushback lately and may be jeopardy in the future. In addition, the rules for connecting to the grid act as a barrier in many jurisdictions.

### *4.2.1 Net Metering Fights*

While highlighted above as a driver, net metering is encountering a series of challenges as solar penetration increases and utilities are reaching the limits of the amount of electricity that can be fed back into the grid without significant investment and upgrades. Utilities point out that the additional costs required to accommodate net metering are spread among the entire rate base, not just tacked onto homeowners with solar on their rooftops. In the United States, some utilities are introducing fixed fees to consumers with solar installations to cover some of its grid costs. The Arizona Corporation Commission concluded that concerns about the cost shift are real and imposed a fee of CAD$0.93(US$0.70)/kW of installed solar, which would equate to about CAD$6.7(US$5) per month in a typical household. Although that is but one-tenth of what the power industry had advocated, spending millions of dollars to lobby the Arizona regulators and influence public opinion, this resolution may have some impact in future

negotiations. Similar negotiations have been undertaken in other states like Nevada, California, and Massachusetts, with a wide range of potential outcomes based on the parties and politics involved.

Furthermore, fixed utility fees such as system demand charges and transmission fees make up a significant portion of the final customer bill—thus diluting the impact of the actual generation cost on the consumer electricity bill.

### *4.2.2 Interconnection Standards*

Interconnection standards specify the technical and procedural process by which an electric customer connects an electricity-generating system to the grid. Interconnection standards include the technical, contractual, metering, and rate arrangements by which system owners and utilities must abide. Standards and permitting are often cited as two of the more arduous and costly tasks in the development of a DER system. Both BTM and grid-tied systems are subject to electrical codes at the local level. Code requirements emphasise the safety of the individual as well as the installation of the system. Accordingly, all systems and their components must be certified for fire and electrical safety.

In the United States, standards for systems interconnected at the distribution level are typically adopted by state public utility commissions, while the Federal Energy Regulatory Commission has adopted standards for systems interconnected at the transmission level. Interconnection standards vary from state to state in the United States, while worldwide standards vary depending on the policies of individual countries. A trend toward the creation of international standards is developing across Europe and Africa, where the wheeling of power between countries is increasing.

The bottom line is that connecting to the grid is costly for DER developers. Creating and publishing standard rules and transparent cost structures will lower interconnection costs and facilitate the development of DER in developed nations. Efforts are underway in the United States and Europe to create standard rules for interconnection and cost sharing that will benefit both energy producers and grid operators.

## 4.3 Incumbent Market Players

Traditional utilities and generators have a large stake in the future energy mix on the grid. Traditionally, utility business models, which date back over 100 years, have been based on the idea that profits are made by selling more electricity. Therefore, it would be expected that some utilities would be resistant to the changing energy landscape that includes technologies that empower customers to assume better control of their energy use and reduce their energy consumption and energy bills, thus reducing electricity demand, decreasing electricity sales for utilities, and threatening profits. There is little direct financial incentive for electricity companies to adopt new policies that could hurt their bottom line when electricity usage has been steadily climbing for decades.

Additionally, utilities can be wary of new technologies and traditionally do not like to be first movers in a new space. Utilities value dependability—some have been using the same power plants since their construction in the 1950s. Utilities want to know that a technology will be reliable and have a long lifespan before investing, especially since the procurement process can be so extensive. Natural scepticism and the resistance to change in an evolving energy space can cause a major barrier for the implementation of DER programs.

However, it is certainly not the case that all utilities act as barriers to DER development, and some have taken proactive stances for the benefit of their companies and their customers.

## 4.4 Grid Infrastructure Deficiencies

Rapidly expanding investment in DER represents a major shift away from the centralised, one-way electrical grid that has been the status quo for the past century. This growth has generated both concern and optimism throughout the power industry as regulators and grid operators work to understand the evolving landscape that is redefining the relationship between utilities and their customers. Specifically, the shift away from centralised generation will require the use of innovative technologies and solutions on the part of grid operators, including advanced software and hardware that enables greater control and interoperability across heterogeneous grid elements that are all key components of the emerging energy cloud. DER developments are challenging incumbent grid operating models, requiring a more dynamic and flexible network with advanced communications and orchestration to ensure stability, efficiency, and equality among diverse resources.

The growing market for DER and the variable nature of PV have the effect of increasing the complexity of operating the electrical distribution network. Connecting to the power grid creates technical and safety issues for grid operators and for the owners of the DER. Utilities need to be sure that the power from solar and other distributed energy systems synchronises with and matches the voltage, frequency, and power quality of the grid. Electric power from a few small-scale distributed resources can easily be absorbed into the grid, but as the market grows and larger and community-based projects come online, the stability of distribution systems could be affected.

A study conducted by the European Photovoltaic Industry Association concluded that in order to reach the European Union's (EU's) goal of 12% of electricity from solar, smart grid technologies would need to be implemented to effectively manage the load. Such upgrades will take time and could limit the pace that DER can integrate into the system.

## 4.5 Low Electricity and Natural Gas Prices

The impact of low-cost natural gas on North American retail electricity prices, combined with decreasing demand overall, has reduced the competitiveness of DER over the past few years. Looking ahead, the impact of natural gas will be different in each region based on the existing electricity mix and how rates are structured for each utility.

Natural gas prices outside of the United States are forecast to remain high during the next 10 years, especially in Europe, which is still primarily dependent on Russia for its natural gas supplies. Meanwhile, the low price of carbon is failing to adequately drive up coal electricity prices, which has prevented broader European retail electricity rates from increasing faster. In Germany, however, the wholesale rates of electricity have actually declined due, in large part, to reduced demand caused by the increase of distributed solar, while retail rates have increased. To the point where, the cost of electricity in German homes with 4 kW onsite solar systems are forecast to be lower than the prices for grid electricity.

# 5. MARKET DESIGN CONSIDERATIONS: TECHNICAL

Looking at the technical aspects of DER, there are advancements related directly to the resources that will enhance the ability to integrate DER into the grid.

## 5.1 Crucial Technologies and Innovations

The state of DER technology will be far from static over the next several years. New advances are expected on a regular basis to improve the efficiency of products and reduce costs of materials and production.

### *5.1.1 Smart Inverters*

The single most important technology advancement enabling DER is smart, bidirectional inverters that are capable of allowing islanded resources to continue to operate, even if these resources have historically been required to disconnect in the event of a power outage.

An inverter is a device that converts DC from generation sources to AC at the voltage and frequency required by utility distribution companies (i.e., 60 Hz or 50 Hz). Recent advances in inverters necessary for solar and small wind turbines are setting the stage for a viable DER market to evolve, transforming resources previously viewed as villains to grid reliability and stability into heroes that solve a growing list of distribution-level power quality challenges.

Next-generation smart bidirectional inverters allow for safe islanding. They enable DER to continue operating when the larger grid goes down, thus avoiding the feeder fault concerns associated with synchronous generators, which may take several seconds to respond to a grid outage. Under standard utility protocols, all DER is to shut down during a power outage, the exact time when they offer the highest value: clean and reliable power (if backed up by energy storage). Tripping these resources offline can also cascade problems, leading to even larger power outages. With the help of these new islanding inverters, what was once viewed as a problem for utilities—backflow of power from DER back onto the grid—instead is transformed into a smart grid solution.

### *5.1.2 Energy Storage Batteries*

The confluence of key project-level factors is fostering the growth of the energy storage sector:

- Lower battery cell, pack, and battery management system costs;
- Improved battery power and energy densities;
- The unique flexibility of battery energy storage systems to provide multiple grid and customer benefits; and
- A better understanding of what battery energy storage and balance of system components need to do to meet power market and customer requirements to deliver predictable revenue streams

Given these developments, it is believed that the energy storage sector will leverage the lessons learned from distributed solar to quickly standardise how energy storage system components should be built and how they should perform and communicate to each other and the grid. This modular evolution will allow project developers and energy storage system hardware and software suppliers to apply traditional lean

manufacturing concepts to rapidly reduce project costs. It is also expected to result in more modular energy storage systems with standardised power and energy performance capabilities and lower costs over the near- to mid-term. Furthermore, as part of this evolution, the flexibility of lithium ion (Li-ion) batteries to address not only short-term power applications but also longer duration energy applications of four hours or less will be optimised.

The early days of solar markets were fraught with a lack of standard protocols for how solar cells, inverters, utility meters, and the grid connected and communicated to each other. Additionally, the ability to tie potential design and performance of a solar system to software tools that could estimate the solar production and associated potential project revenue was at its infancy. Over the last several years, the solar industry has focused significant efforts on streamlining and simplifying these standards, hardware components, and software tools in order to reduce costs. For example, initial solar design and solar electricity production estimating software models can now often be credibly developed in just a few short hours. Solar projects are easier to develop and finance, and systems are more plug-and-play ready. The result is reduced costs as well as improved safety. The solar industry has also applied lean principles to the manufacturing, procurement, delivery, and installation of system components, thus creating further cost savings for system installers. To further build on these previous successes, efforts are now underway in the solar sector to focus on streamlining permitting, interconnection, and inspection protocols.

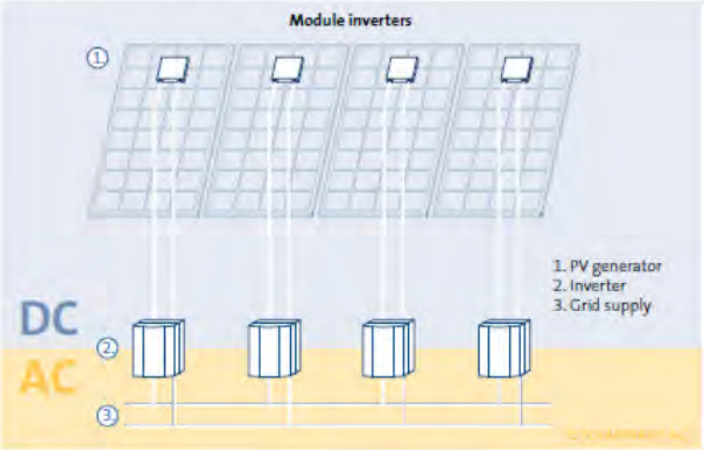
These solar sector streamlining and efficiency success stories have created significant value over the past decade. The move towards more simple and modular solar systems took time, mostly due to the lack market volume and variations in state policies and local solar insolation. However, it is anticipated that by identifying these hurdles early on, the energy storage sector will apply the lessons learned from the solar industry to likewise streamline component construction, interoperability, project development, engineering, and installation.

### *5.1.3 Improving Efficiency of Solar Photovoltaic Systems*

The weakness of solar has been its low efficiency. Even the most efficient monocrystalline silicon photovoltaic panel has only 20% efficiency, though the majority of modules installed today range from 10% to 16% (compared to wind at 30% and fossil fuel generators at 80%-95%). Concentrating solar photovoltaic modules, perovskite, and other innovations to manufacturing processes will continue to improve conversion efficiency.

However, module efficiency is only one factor in determining a solar system’s overall output; shading, dirt, cabling, voltage drop, inverter efficiency, and heat also affect the overall energy harvest. Micro inverters and direct current (DC) optimizers are two enabling technologies at the module level that are gaining traction. In some cases, micro inverters are already being fully integrated to create alternating current (AC) modules.

**Figure 5-1. Module-Level Power Management**




*Source: Solarpraxis AG*

### *5.1.4 Micro inverters*

Micro inverters are installed on the back of each solar panel, matching the rated capacity. Each panel's DC power is converted directly to AC, 120V or 240V, and grid-tied. The output of each is effectively in parallel, eliminating power losses due to module mismatch and creating a higher energy yield by preventing a single panel's failure from affecting the overall system's energy harvest (as is the case with most string architectures). With micro inverters, each panel is effectively individually monitored, providing system owners with a detailed view of solar system performance regardless of whether the system is composed of 10 solar modules or more than 1,000.

This architecture distributes the overall risk of failure among the number of panels in the installation, removes the need for DC cabling, and leverages information technology to identify and isolate a problem panel. In contrast, central inverters, though more efficient, have a single point of failure, which can lead to longer periods of downtime. The downside to micro inverters is that they are 30%-50% more expensive than string inverters and have lower efficiencies (though they do typically result in a better overall energy harvest). While the distributed architecture removes the risk of a single point of failure, micro inverters introduce many more electronics into the PV system, adding technical risk.

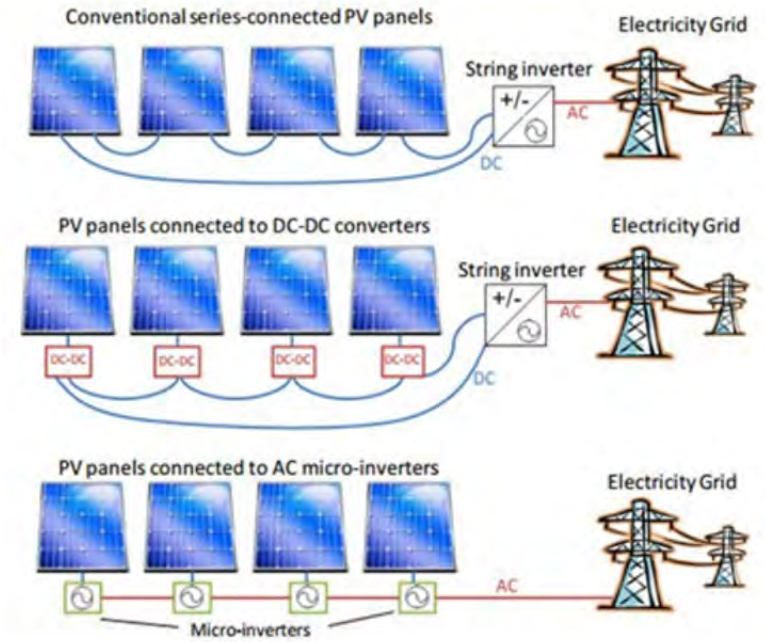
### *5.1.5 DC Optimizers*

DC optimizers have benefited from the success of micro inverters. Venture dollars, massive marketing budgets, and strong technical performance have won many installers over on the concept of module-level management. Riding the wave of micro inverters, DC optimizers represent similar module-level architecture, increasing energy harvest by optimising operating voltage along each string; however, they still require a string or central inverter. The main functions of DC-DC power optimizers are to provide maximum power point tracking and to harvest the maximum amount of power from each module.

The advantages of power optimizers within a string inverter installation are numerous. They standardise the operating voltage of each string, resulting in greater yields at the output of the string inverter(s). They greatly minimise the detrimental effects of module mismatch, soiling, partial shading, and/or snow cover on one or more modules within a string. According to a 2010 Photon Labs study, Tigo maximisers increase yield by approximately 1%-3% when modules are soiled and by 2%-36% when modules are partially shaded. This is when compared to modules with no maximisers. Power optimizers do not halt power generation in the case of failure. Instead, should an optimizer in an array fail, the associated

module continues to generate power into the string inverter. If a micro inverter fails, the effective power generated by the associated module is zero. They also allow for web-based module-level monitoring.

**Figure 5-2. Module-Level Power Electronics Topologies Compared to Conventional String Inverter**




*Source: National Renewable Energy Laboratory*

## 5.2 Case Studies: Integration into an Existing Market or System

Until the last decade or so, DER existed outside of wholesale and utility market operations. Utilities and regional transmission organisations (RTOs) had standalone programs for demand response and energy efficiency, while solar, electric vehicles, and storage capacity was too small to warrant extensive integration. With all of the transformative drivers mentioned earlier in the report, integration has moved from a nice-to-have to a must-have for grid operators.

### *5.2.1 Southern California Edison's Pre-Engineered Energy Storage Systems*

In 2015, Southern California Edison (SCE) issued a request for proposal for what it termed to be plug-and-play battery storage systems to meet a series of local grid congestion needs within its distribution network. SCE intended to have a standardised, modular, energy storage system that could be constructed in a standard container, shipped, installed, and interconnected to the distribution grid within seven months of contract award. The approach was based on having the vendor provide a pre-engineered, approved storage solution—defined as a combination of batteries, power converters, and control systems that are already proven in field tests and compatible with SCE's grid control systems.

This unique step forward in the energy storage sector by SCE was driven by a combination of three factors:

- SCE's early adopter lessons in energy storage driven in part by mandatory requirements for California utilities to procure energy storage;
- Its high peak load growth; and

- Its aging grid infrastructure.

This case is the first of its kind in the United States and represents a step forward in the maturation of the storage market. It is anticipated that other utilities will follow.

### *5.2.2 South Korea*

The Korea Power Exchange (KPX), the transmission grid operator for South Korea, implemented its Smart demand response program, an all-automated demand response approach for C&I customers, several years ago. It also had its Smart demand response initiative, in which it pursued 500 MW of wholesale market demand response participation, achieved through capacity auctions and other market-based mechanisms similar to the constructs in the U.S. RTO markets such as PJM and Independent System Operator-New England (ISO-NE). These programs were funded by the government, separate from the competitive electricity market.

Starting in December 2014, the federal electricity act allowed demand response to compete equally with generators in the electricity market. The main reason for the law change was the government's shift in electricity policy, going from generation-side electricity supply to demand-side promotion. That helped get rid of demand response providers' suspicion that the government would stop funding demand response if enough generation resources were available in the near future. Demand response providers can now aggregate more demand response because they are sure that a persistent market will be established.

The demand response program in Korea starts with seasonal procurements of demand response resources. Demand Response may bid into the day-ahead energy market within the committed load reduction; it is then obliged to reduce up to the committed load reduction when KPX orders a load reduction in real time. The KPX demand response program is intended to encourage demand response aggregators to participate in the market, and utilities such as Korea Electric Power Corporation (KEPCO) are not allowed to participate. The program is likely not an immediate threat to KEPCO since it is limited in its overall capacity level in relation to the size of the South Korean electric grid. Outside of the KPX program, there could be opportunities for KEPCO to use demand response to optimise its own assets outside of the KPX market.

## 5.3 Case Studies: System Operator Visibility into DER Dispatch

DER installations do not occur in a vacuum. Customers may install DER to address their own energy usage and reliability, but as the DER base grows, it can have unintended consequences on the larger grid. Without any intentional planning and standards, the grid operators may have no direct visibility into DER operations and cannot accurately manage the flow of power. However, there are examples of grid operators that have taken this issue into account and devised ways to obtain better visibility and control of DER.

### *5.3.1 ISO-NE*

In its summer 2016 system forecast report, ISO-NE reported that it had 1,300 MW of behind the meter solar installed throughout its system. Because it is not visible to operators, it will be a challenge to determine how much power they will produce and when and where that will happen. All the operators see when distributed solar panels produce power is a drop in demand on the transmission system. On clear sunny days, the output from panels offset the use of other generation during the afternoon, but once the sun sets, the energy quickly disappears.

To address this concern, ISO-NE has led the way in attempting to forecast distributed generation on its system and created a distributed generation Forecasting Working Group. This group, made up of utility, government, and industry representatives, develops an annual and long-term view of DG growth, primarily solar, on the grid. The goal is to get as granular as possible and to discuss issues ranging from the effects on the system load curve to interconnection requirements to technology developments such as smart inverters. The results from the forecast appear in the annual Capacity, Energy, Loads, and Transmission (*CELT* Report), which is the ISO's ultimate source for grid planning purposes.

The ISO looks at both larger-scale distributed generation that participates in its markets and behind the meter systems that only show up as a reduction in system load since they are not directly metered. Solar projects under 5 MW are not required to register with the ISO as a generator and provide meter data. Basically, the ISO puts together state-level solar forecasts for capacity and hourly load and then subtracts out the known solar participating in its markets to determine the amount of non-market solar.

Such is the current case for distributed solar, which is not yet incorporated directly into the ISO wholesale markets. However, for resources such as demand response and storage that can participate in the markets, the ISO has detailed requirements for metering and communication to ensure operator visibility. ISO-NE has the strictest requirements of any of the RTOs that allow demand response participation. Some RTOs simply require utility interval meters with performance reports done 60-75 days after a demand response dispatch event. ISO-NE, on the other hand, requires five-minute metering with near real-time communication to the ISO. Such standards mean that the demand response aggregators need to install additional metering equipment at the customer's site, along with some form of communication at the site and a communication infrastructure in the aggregator's network operations centre to move the data from the customer to the ISO in a timely manner.
These high standards add significant costs for aggregators to participate in the ISO-NE market and are partly responsible for the low number of aggregators and customers involved in the market compared to other regions. Ideally a reasonable balance can be found between the needs of the grid operator and the cost-effectiveness of the resources.

### *5.3.2 Germany*

Germany produced 28 percent of its energy from renewable sources in 2014 and set a new record peak of 27,700 MW of actual production capacity on April 15, 2015—covering more than 75 percent of the demand and prompting negative electricity prices. That is becoming increasingly normal. In August 2015, prices fell to $CAD88 (€59[13]) per MWh to incentivise exports pushed by a peak electricity production of solar and wind of 32,000 MW between 1 p.m. and 2 p.m.

One way Germany is able to address the high penetration of solar on feeder lines is that the grid operator can simply curtail solar systems below five kW in size since every distributed energy installation features a second meter controlled by a utility or grid operator. It should also be noted that the entire EU is abolishing the standard utility protocol of requiring solar and wind turbine inverters to disconnect from the grid during a transient disturbance, even one of short duration. This action removes one more barrier for solar in Germany and other leading European countries over the next few years.

Despite major increases in distributed renewable energy deployments, Germany has suffered remarkably few blackouts, and there is little indication that the increase in renewables has led to a greater number of outages. One contributing factor, perhaps, is that for the most part, countries within Europe are strongly

[13] CAD$1 = Euro€0.67, Foreign exchange currencies have been converted to CAD using the average exchange rate in the first quarter of 2016

interconnected, such that power is widely shared across borders and helping to mitigate the issue of variability that renewables present to regional grid systems.

## 5.4 Case Studies: DER Customer Obligations

Aside from the grid operator side of the DER process, a customer's requirements must be kept in mind as well. Different markets require varying levels of information and technical capabilities to enable market participation.

### *5.4.1 NYISO*

Since the announcement of the New York Public Service Commission's Reforming the Energy Vision (REV) initiative, there has been a growing interest in wholesale market participation of storage resources. In 2016, NYISO undertook a process to better integrate and optimize energy storage into its markets. In the short term, NYISO is evaluating its current programs in which energy storage resources can participate and assessing potential needs for expanding and/or enhancing such existing programs. In the longer term, NYISO will evaluate storage optimisation techniques that will provide additional tools to aid the scheduling of storage resources.

NYISO has several existing products in which storage could participate, but the rules for each may not account for the unique characteristics of storage as compared to traditional generation resources.

- **Energy Limited Resource (ELR):** To be eligible to sell capacity, the resource must be able to provide at least one MW of grid injection for at least four consecutive hours and aggregation is not supported.
- **Limited Energy Storage Resource (LESR):** Eligibility is limited to storage resources that can sustain maximum injection or withdrawal rate for less than one hour. Must have at least one MW of dispatch capability and aggregation is not supported.
- **Demand-Side Ancillary Services Program (DSASP):** Load that is curtailed with the use of local generation may only provide 10 and/or 30 minute non-synchronous reserves. Load with storage is currently considered as a resource eligible for non- synchronous reserves. Aggregation is allowed.
- **Special Case Resources (SCR):** To be eligible to sell capacity, the resource must be able to provide at least 100 kW of load curtailment for at least four consecutive hours and aggregation is allowed. Load with storage can be in the SCR program as long as it can meet all the program requirements.

None of these products are perfectly crafted for storage or other DER resources, so each requires modifications to its rules, which can entail a lengthy stakeholder process. In the long term, NYISO will consider increasing bidding and optimisation flexibility for offering storage and other DER into the day-ahead and real-time energy markets.

### *5.4.2 CAISO*

In 2015, the California Independent System Operator (CAISO) released a proposal to allow aggregated distributed resources to bid into its markets. CAISO found a way to introduce a new acronym, distributed energy resource provider (DERP), into the industry lexicon. This DERP proposal was part of the Expanding Metering and Telemetry Options stakeholder process at CAISO, which was started in fall of 2012. One scenario that came out of that working group effort identified the need to enable metering and

telemetry scenarios for aggregations that would allow a third party to provide data consolidation services for resource owners.

The proposal lays out a framework for aggregated resources of at least 500 kW to participate in the wholesale market. There is also a requirement that aggregators serving more than a single grid pricing point must be limited to a single type of technology. Metering has been one of the hurdles to demand response participating in CAISO markets because the system requires generation-scale monitoring. The new rules would allow demand response to be aggregated via the Internet, providing for a broader range of resources to be brought to market with less cost. DERP aggregators will be a scheduling coordinator-metered entity, which will avoid "having each sub-resource in a DERP aggregation engaged in a direct metering arrangement with the CAISO. Access to ancillary markets, however, will still require resources to allow constant real-time monitoring by CAISO.

A critical element in this effort was the potential for parties to collect and submit metering data—with appropriate audit control—instead of the standard requirement that CAISO collects all meter data. This point becomes crucial for resources made up of many small sub-resources. The standard requirement is expensive for a variety of reasons and would ultimately require CAISO to manage meter data collection for a much larger set of assets than it did prior.

# 6. MARKET DESIGN CONSIDERATIONS: FINANCIAL

While operational concerns are critical to the ultimate success of DER integration, the economic case for it will make or break its ability to scale up significantly. Such financial considerations include sources like market payments, reliability value, and policy incentives.

## 6.1 Case Studies: Compensating DER Users for Backup Power

There are numerous models for paying DER for participating in energy markets and programs.

### *6.1.1 United Kingdom*

National Grid, a U.K. transmission system operator (TSO), operates the grid in England, Wales, and Scotland, while System Operator for Northern Ireland operates the grid in Northern Ireland. These TSOs balance the system and ensure that supply meets demand on a second-by-second basis.

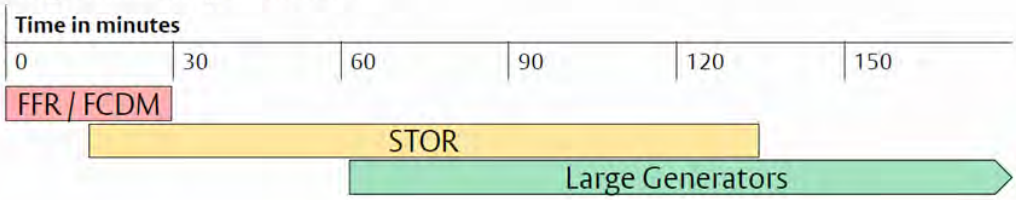
Most of the energy market (greater than 90 percent) is settled through bilateral contracts between generators, suppliers, and other parties and then distributed to customers. Final balancing and settlement is done through contracts mediated by National Grid. The majority of the DER capacity resides in commercial and industrial facilities through National Grid's short-term operating reserve (STOR) market, which is reserve power in the form of either generation or demand reduction able to deal with actual demand greater than forecast demand and/or plant unavailability. STOR capacity is awarded by tenders, which results in varying pricing. Demand response may also participate in the frequency response markets— including firm frequency response—which provides firm provision of dynamic (continually matching) or non-dynamic response (set points) to changes in frequency and frequency control by demand management, which provides frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting onsite (see Figure 6-1).

**Figure 6-1. DR Participation Parameters, United Kingdom**

- Market programme participation parameters summary

| Programme | Response time | Duration (max) | Minimum MWs | Trigger |
|---|---|---|---|---|
| FFR - Primary | 2 to 10 seconds | 1 to 2 minutes | 10 | Static or Dynamic Frequency |
| FFR - Secondary | Up to 30 seconds | 30 minutes | 10 | Static Frequency Point |
| FCDM | 2 to 10 seconds | 30 minutes | 3 | Static Frequency Point |
| STOR | Up to 20 minutes | 2 hours | 3 | National Grid Request |

- Programme usage timeline




*Source: University of Reading*

Aggregators play a key role in the demand response market, especially as many of them are supporting the STOR program. A number of U.K. aggregators are able to support these fast DR programs through automated demand response capabilities. Honeywell is working with power management company Stor Generation Ltd. to help companies in the U.K. automatically adjust energy use in their buildings to help stabilise the electrical grid. Stor Generation will provide aggregated electricity reductions from many buildings to programs like the STOR initiative. Stor Generation can combine and feed power from onsite generators into the grid as well.

### *6.1.2 Electric Reliability Council of Texas*

The Electric Reliability Council of Texas (ERCOT) has two current demand response programs that allow backup power use:

- **Load Resources:** This program allows demand response to participate in the ancillary services markets in ERCOT. It has stringent metering and control requirements for participation.
- **Emergency Response Service (ERS):** This is more of a typical demand response program that is called during emergencies. However, until recently, ERS had a 10-minute response time requirement, which is much faster than other emergency programs. ERCOT piloted a 30-minute ERS program in 2012 that proved popular; it is now a fully operational program option.

**Table 6-1. ERCOT DR Program Requirements**

| Name | Service Type | Min. Eligible resource Size | Aggregation allowed | Trigger Logic | Max. sustained response period | Ramp Period | Sustained Response Period | Recovery period | Telemetry requirement | Telemetry reporting Interval |
|---|---|---|---|---|---|---|---|---|---|---|
| **ERS – 10 minutes** | Capacity | 100 kW | Yes | operational procedure | 12 hours | 10 Minutes | As Dispatched / Recalled | 10 Hours | No | N/A |
| **Non-Controllable Load Resources providing Responsive Reserve Service – Under Frequency Relay Type** | Reserve | 100 kW | No | operational procedure or Automatic Response | N/A | 10 Minutes (Verbal) 30 Cycles (Relay) | As Dispatched / Recalled | 3 Hours | Yes | 2 Seconds |
| **Controllable Load Resources providing Responsive Reserve Service** | Reserve | 100 kW | No | operational procedure or automatic response | N/A | Continuous primary FR, similar to generator governor action; and 10 minutes (1 minute to release capacity to SCED) | As Dispatched / Following SCED Base Points until Recalled | N/A | Yes | 2 Seconds |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Controllable Load Resources providing Regulation Service** | Regulation | 100 kW | No | automatic response | N/A | Effectively Immediate | Primary Frequency Response Continuous / AGC as Dispatched / Recalled | N/A | Yes | 2 Seconds |

*Source: ERCOT*

To address the proliferation of DER in Texas, ERCOT initiated its Distributed Resource Energy and Ancillaries Market (DREAM) Task Force in 2015. The primary mission of the task force is to provide a forum for stakeholders and ERCOT staff to develop market rules related to DER. The task force will consider and recommend a potential market framework that allows DER an opportunity to more fully participate in the ERCOT wholesale market including, but not limited to, participation in security-constrained economic dispatch and the ancillary services market.

DER pricing at the zonal level often dilutes incentives that could otherwise provide significant benefits to the grid and the market. Enabling DER to be settled on nodal pricing could better align their decisions to generate power with grid conditions and thus enhance grid reliability. The task force is contemplating three categories of DER participation/settlement in ERCOT markets:

- **DER Minimal,** which would be settled at load zone settlement point prices, essentially unchanged from current practice
- **DER Light** (either single site or aggregations), which would participate passively in the energy market while settled at nodal prices via mapping of the DER location(s) to their appropriate common information model load point(s)
- **DER Heavy** (either single site or aggregations), which would participate actively in the energy and ancillary services markets while settled at nodal prices via mapping of the DER location(s) to their appropriate common information model load point(s). In many respects, DER Heavy would be treated similarly to generation resources in the current market construct. A key feature of a DER Heavy is the assignment of a logical resource node settlement point and a settlement point on the transmission grid.

ERCOT's proposal would not require any metering changes, unless a DER chooses to seek DER Light or DER Heavy status in order to attain nodal pricing. In those cases, in order to maintain compliance, DERs Light and Heavy would require a type of metering configuration not currently in place in many ERCOT footprints. Dual metering—separate measurement of gross generation and gross native load—at DER Light and DER Heavy sites will be necessary to ensure that load at the same service delivery point continues to be settled at the load zone settlement point prices while the onsite generation is settled at the nodal price. The ability to separately meter gross native load and gross generation could enhance retail competition by opening up potential new business models for retail electric providers.

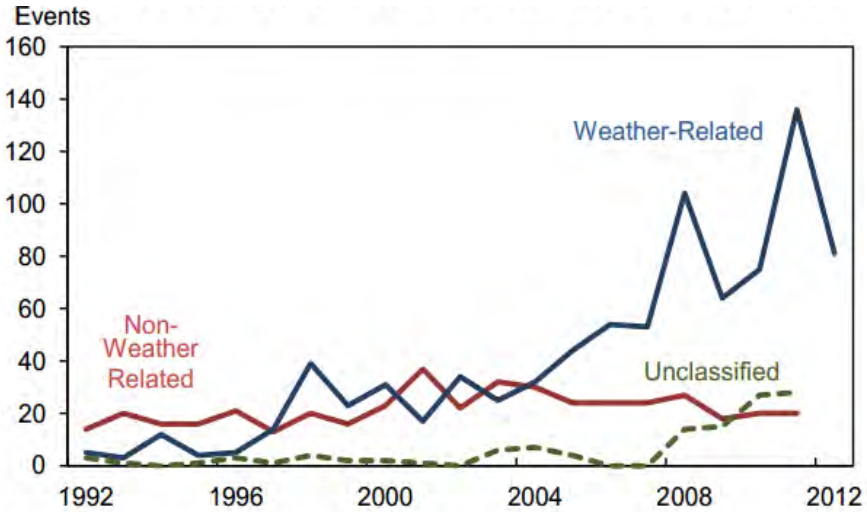
## 6.2 Regulate and Fund Reliability Enhancements Behind the Meter

Since Hurricane Sandy hit the Atlantic Seaboard in 2012, a concerted effort has been made by utilities, governments, and businesses to ensure that the electric grid can withstand such natural disasters in the future. Hurricane Sandy left millions of homes and businesses in New Jersey, New York, and Connecticut without power for days and even weeks in some places. Since most of the electric system in New York

City is underground, a measure that increases reliability most of the time, it was flooded and rendered out of commission during the storm. Princeton University in New Jersey and New York University in New York City were literal islands of light during this time of darkness due to their CHP systems that continued to run after the larger grid went down.

Whatever the reason, weather-related electric outages appear to have increased over the last 20 years, as seen in Figure 6-2.

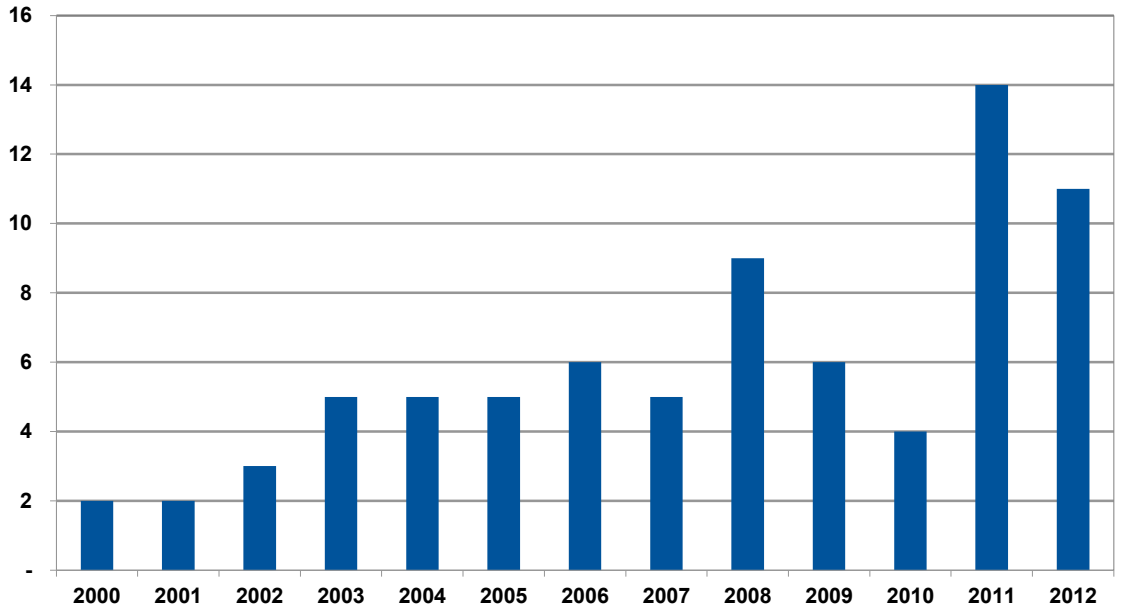
**Figure 6-2. Observed Outages to the Bulk Electric System, United States: 1991-2012**




*Source: U.S. Energy Information Administration*

The economic impact of these outages has increased as well, with the number of billion-dollar storms rising. Consequentially, insurance costs in the affected areas and other areas that may be prone to similar weather activity are also rising (see Figure 6-3).

**Figure 6-3. Billion-Dollar Weather- and Climate-Related Disasters, United States: 2000-2012**




*Source: National Oceanic and Atmospheric Administration*

For both grid operators and end-use commercial customers, there is tremendous value in strategies such as DER that can help mitigate the risk and effects of disasters that are beyond the control of a business owner. These types of societal costs and risk-reduction values must be taken into account regarding policy choices and individual facility decisions.

### *6.2.1 Connecticut*

Even before Hurricane Sandy, *Connecticut was one of the first states to encourage microgrids, thanks in part to its central role in fostering the fuel cell industry. In an* integrated resource plan released in December 2014, the state's Department of Energy and Environmental Protection specifically called for new incentives to add 160 MW of CHP in the state. The plan states that CHP "can provide special value in locations where it can power microgrids" as well avert upgrades to utility distribution systems and reduce the use of natural gas and electricity.

*Connecticut offers an incentive of CAD$600(US$450)/kW to businesses that want to install a CHP system.* The state figures this is the right amount to allow businesses to achieve a reasonable payback period considering the estimated cost of installations, the value of the energy offset by the system, and the overall cost-effectiveness of the system. Ultimately, the state envisions creating a competitive process that offers CHP incentives in blocks of funding rounds on a first-come, first-serve basis.

### *6.2.2 New Jersey Energy Resilience Bank*

The New Jersey Energy Resilience Bank (ERB) opened in October 2014 as a collaboration between the New Jersey Economic Development Authority and the state's Board of Public Utilities. The ERB supports the development of DER at key facilities state-wide—such as hospitals, waste water treatment facilities, and universities—that will help them to remain operational during future outages. The bank funds projects from a pool of CAD$267(US$200) million, which comes from the U.S. Department of Housing and Urban Development's Community Development Block Grant Disaster Recovery program.

The ERB covers 100 percent of successful applicants' unmet funding needs after other funding possibilities, including insurance payments, are exhausted. Of the total, 20 percent of the funding will be in the form of a grant, with another 20 percent being in the form of debt forgiveness. The other 60 percent comes from low-interest financing at a two percent rate for investment-grade borrowers and 3 percent for all others. Eligible facilities must have suffered physical damage from one of the qualifying storms or otherwise be supporting revitalisation efforts in a community where flooding or a loss of power prevented wastewater or drinking water treatment.

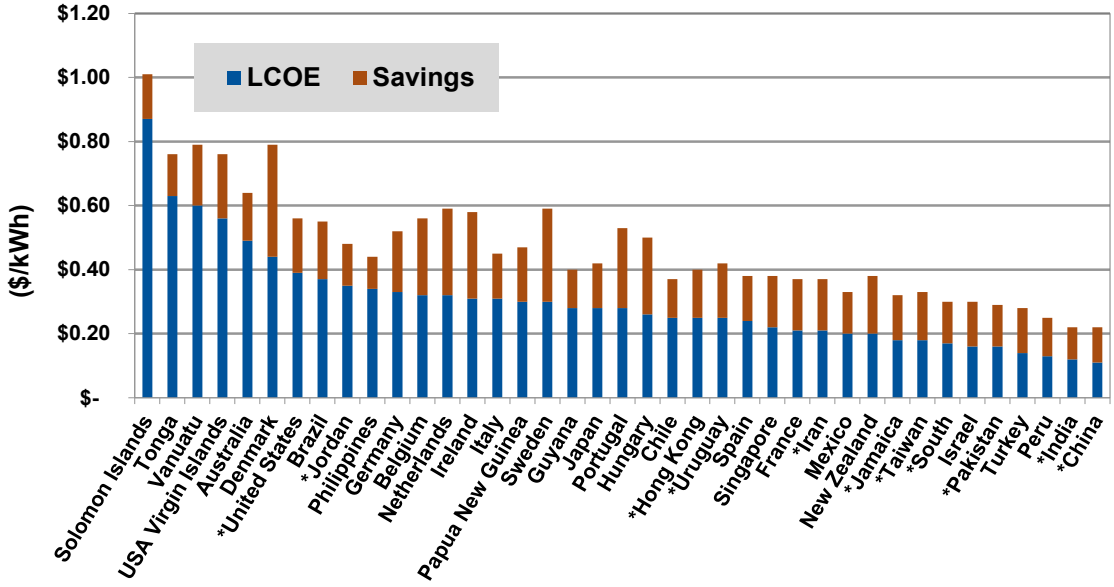
## 6.3 Price Sensitivity to Consumers Investing in DER

As highlighted throughout this report, for any given technology set, the financial return will determine the viability and scalability of the solution. There are technology-specific and broader market trends that will impact this analysis. In reality, DER is a dynamic market where customers are starting to make decisions without necessarily having the architecture in place to accommodate their ultimate solution, so choices are made in a bit of a vacuum. The evolutionary pace of technology and policy development may not keep up with the pace of consumer demand for new products.

### *6.3.1 Solar PV Economics*

In a recent analysis, Deutsche Bank compared the retail electricity price with the levelised cost of energy (LCOE) using solar in over 60 markets. It discovered that roughly 30 markets had reached grid parity in 2014. Although a significant number of markets have excellent solar resources that help to make solar competitive with other sources of electricity, the most important factor to determine if solar is at grid parity is the local electricity price. The list includes some large markets like Germany, where competitiveness is driven by a high average electricity price (CAD$0.44/kWh, US$0.33/kWh in 2014) despite low solar irradiation. By contrast, Saudi Arabia has very low electricity prices but high solar irradiation. According to Deutsche Bank, the levelised cost of electricity from rooftop solar in Germany is CAD$0.25(US$0.19)/kWh; in Saudi Arabia, it is as low as CAD$.15(US$0.11)/kWh (see Figure 6-4).

**Figure 6-4. Countries at Grid Parity, World Markets: 2015**



*Source: Deutsche Bank*

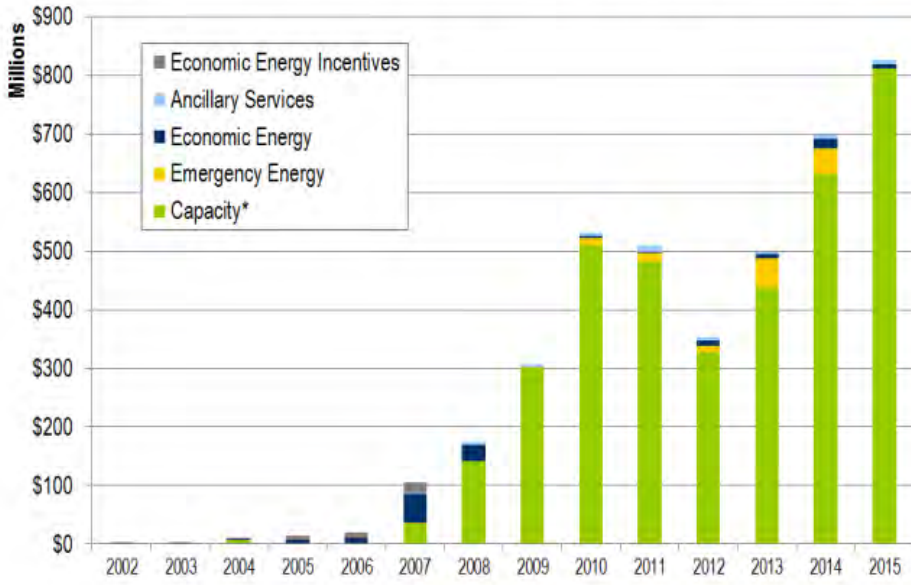
In the United States, solar is currently competitive in 14 states without local subsidies. The levelised cost of electricity in those states ranges between CAD$13(US$10)/kWh and CAD$20(US$15)/kWh, while retail prices vary between CAD$0.16(US$0.12)/kWh and CAD$0.51(US$0.38)/kWh. If the installed cost of solar continues its downwards trend of 4 percent to 10 percent per year in the United States (as it is expected) and electricity prices continue increasing at 1.7 percent per year nationally, nearly 47 states, theoretically, would be at grid parity be the end of 2016; however, due to changing tariff structures set by utilities, including increasing demand charges, limiting net metering, and adding fixed fees, this is not likely. The future growth of distributed and non-distributed solar in the United States was bolstered, however, by the long-term extension of the investor tax credit in late 2015. The investor tax credit is now extended for both residential and commercial projects, at the 30 percent level through the end of 2019; it then steps down to 26 percent in 2020 and 22 percent in 2021 before dropping permanently to 10 percent for commercial projects and 0 percent for residential projects. The bill included language allowing owners who commence construction on their projects before the end of 2021 to claim the larger credit once their project is placed in service, as long as that project is placed in service before the end of 2023.

### *6.3.2 Wholesale Market Price Fluctuations*

For DER that bids into wholesale markets, price uncertainty presents a large risk to project valuation and investment decisions. There are macroeconomic factors, such as weather and the overall economy, as well as industry-specific trends, such as fuel prices and generator retirements, that affect market prices. In the mid-2000s, energy prices were on the rise as oil and gas prices spiked and the global economy had strong growth. Then came the global economic collapse in 2008-2009, and prices deflated. As the economy began to recover, the shale gas revolution commenced, and a period of relatively low oil and gas prices ensued.

The PJM market provides a good view into how these factors affect DER market participation. As can be seen in Figure 6-5, demand response revenue has varied greatly over the past 10 years.

**Figure 6-5. PJM Estimated Revenue for Economic and Load Management DR Markets**




*Source: PJM*

The capacity market, which includes the vast majority of demand response participation, ebbs and flows with capacity market prices. The economic energy market, which includes day-ahead and real-time markets, was a significant portion of demand response revenue prior to 2009 but has been a minor contributor due to low and stable prices since. Ancillary services are always small in comparison to capacity, but demand response participation in that market fluctuates as well and took a steep dive when a transmission constraint in PJM was eased, dramatically dropping ancillary service prices.

Another important component to keep in mind is the ability of DER to directly affect market prices. The frequency regulation market in a given RTO territory is only a small fraction of the total capacity of the grid. Because of its strict technical requirements, it typically has high prices, which makes it an attractive market to a technology like energy storage, which can meet those standards. However, if a large amount of storage suddenly enters the market and swamps it, the price can quickly drop, flipping the value equation; thus, DER providers need to keep that balance in mind when considering investments.

## 6.4 DER Valuation and Cost Allocation

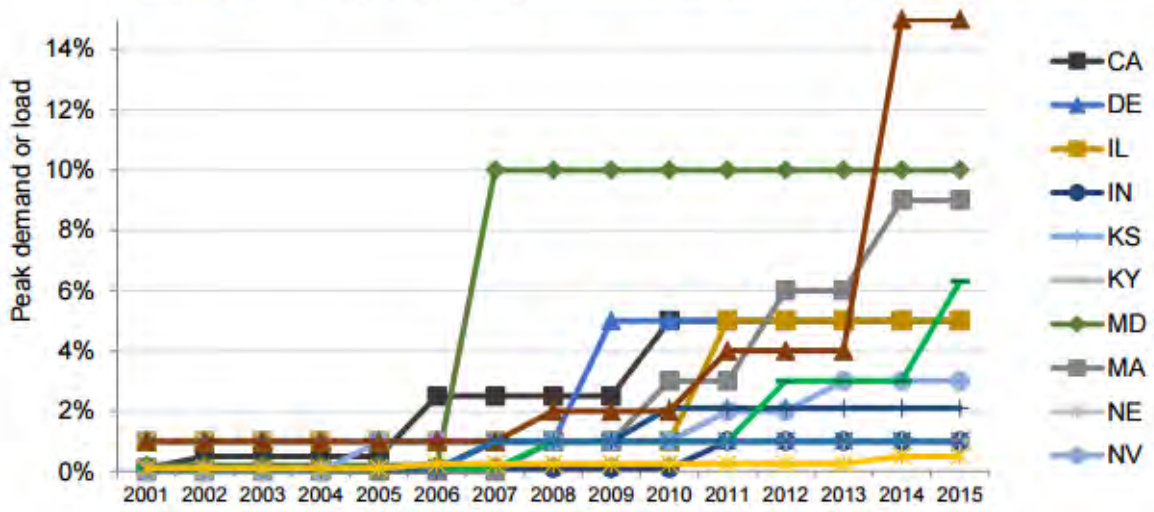
The final area of consideration, which interplays with many of the previous topics, involves figuring out the actual value of DER contributions and how best to allocate those costs to all ratepayers who benefit from them. There is certainly no standard method at this point, and different jurisdictions are trying different approaches to find the right mix.

DER valuation is not a straightforward exercise; it is nuanced and demands the accommodation of many factors. If electrons are getting put back onto the system, how should that oversupply be valued? If it is avoiding transmission expansion, but only a small amount, what is that value? Such values must be compared to the cost associated with plugging a DER customer into a two-way net metering system in order to develop principles that make the rate-making process appropriate. There must be a formula or methodology that includes the use of planning on the central system, which is key, so that the durability of the DER contribution can be considered when developing the future of the system and innovating on top of it.

### *6.4.1 Net Metering Debates*

Net metering is most widely used in the United States, as opposed to other markets in Europe, Canada, or Japan where FIT policies have resulted in all power being fed to the grid, and system owners receiving a payment per kilowatt-hour from the government. With the higher penetration of solar and significant losses in revenue, utilities, particularly in the United States, are actively developing new tariff structures that will have a major impact on the value proposition of DER and especially solar. According to the recently released *The 50 States of solar: 2015 Policy Review and Q4 Quarterly Report*, as of January 1, 2016, 41 states and the District of Columbia had mandatory net metering rules for certain or all utilities. In 2015, there was legislative or regulatory action in 27 states on net metering policies. A growing number of utilities approached or reached net metering aggregate capacity limits in 2015.

**Figure 6-6. Firm Aggregate Caps in State Net Metering Policies, 2001-2015**




*Source: Navigant Research*

### *6.4.2 FITs*

The first modern, cost-based FITs were enacted in the German Renewable Energy Act (EEG) of 2000; these served as a model for numerous other policies in Europe and around the globe. FITs almost always result in the rapid growth of solar deployments, but they also frequently result in large busts once FIT rates are reduced—as in Spain in 2009, the Czech Republic in 2011, Italy in 2012, and Greece in 2014.

2014 proved to be an eventful year for solar PV, as Europe saw significant changes to FITs. Germany amended its EEG to reduce FITs and set constraints on utility-scaled installations, limiting their size to no more than 10 MW. In addition, the country set a limit of 52,000 MW to the overall solar capacity that can be guaranteed financial assistance. Germany also plans to regulate annual solar growth within a range of 2,500 to 3,500 MW by adjusting the FITs accordingly. Finally, it applied the renewables surcharge to power consumed directly. This surcharge was previously applied only to power consumed from the grid, but now it is to be applied to some electricity consumed directly—before it is sold to the grid. Conventional generators are to remain exempt, but commercial solar (systems larger than 10 kW) will have to pay roughly 70 percent of the renewables surcharge, equivalent to CAD$0.05(US$0.04) per kWh.

Distributed solar installations in Germany, the largest European market, dropped to 1,100 MW in 2014—the lowest in the last five years. Utility-scale (non-distributed) projects followed a similar story, falling to 1,000 MW that year. In August 2014, in a dramatic shift, the German government introduced a self-consumption tax for systems with capacity of 10 kW or greater, equivalent to 30 percent of the renewable energy premium that power consumers pay. This move caused a loss of confidence in the solar/DER market.

### *6.4.3 Calculating Value of DER*

The disruption in the utility business model as a result of increasing penetration of DER is both a challenge and an opportunity for utilities. It is clear that the status quo regulatory and compensation structure for utilities has not yet caught up with the technological and business model advancements in the marketplace today. Utilities now seek to establish new tariff structures that account for DER, but finding agreement with industry stakeholders and regulators has been a challenge. Due to the structure of

the electric utility system, particularly in the United States, an analysis of how to appropriately distribute costs/savings is being held, independently, across dozens of jurisdictions.

Discussion to date has primarily focused on calculating the value of solar to the grid, but this coverage is expanded to the full suite of DER more broadly. The following SWOT analysis illustrates the issues that are being addressed in dozens of jurisdictions across the United States.

**Table 6-2. DER SWOT Analysis**

| Strengths | Weaknesses |
|---|---|
| • DER displaces need for new centralised power plant construction, transmission<br>• DER offers opportunity for residential, C&I customers to save money through onsite generation<br>• Technology cost reduction goals being met or exceeded in most cases | • More difficult to forecast short- and long-term demand; utility resource planning<br>• Intermittency of distributed renewables<br>• At higher penetrations, will require storage, adding costs and value |
| **Opportunities** | **Challenges** |
| • New business models overcome the significant capital expenditure hurdle, maximise returns<br>• Utility-managed DER can optimise site selection, locational value (put energy where it is needed)<br>• Aggregated demand response often a least-cost option for procuring new capacity<br>• New markets being established for ancillary services unlock new opportunities for DER | • Limited ability for utilities to control power generation on the grid<br>• Utility business model/tariff structure no longer adequate in high-penetration areas; utilities not known for being innovative<br>• Regulatory structure will likely continue to lag industry innovation, continually<br>• Distributing costs/savings appropriately |

*Source: Navigant*

A few states or utilities have calculated values or ranges of values for solar:

**Table 6-3. State Values of Solar**

| State | Value of Solar |
|---|---|
| Minnesota | CAD$0.15-0.68(US$0.11-0.51)/kWh |
| Vermont | CAD$0.25-0.31(US$0.19-0.23)/kWh |
| Texas (Austin Energy) | CAD$0.17(US$0.128)/kWh |

*Source: Navigant*

In Minnesota, the Department of Commerce (DOC) was required to consult with stakeholders in order to develop the methodology for calculating a Value of Solar Tariff (VOST). The DOC was required to take into account the value of energy and its delivery, generation capacity, transmission capacity, T&D line losses, and environmental value. The DOC was also permitted to consider the cost or benefit of solar

operation to the utility, credit for locally manufactured or assembled energy systems, and systems installed at high-value locations on the grid.

In Vermont, the Acadia Center assessed the grid and societal value of six solar systems to better understand the overall value that solar provides to the grid. By evaluating an array of configurations, this analysis determined that the value of solar to the grid—and ratepayers connected to the grid—ranges from CAD$0.25(US$0.19)/kWh to CAD$0.31(US$0.23)/kWh, with additional societal values of CAD$0.09(US$0.07)/kWh. As a starting point, the National Renewable Energy Laboratory's (NREL's) PVWatts Calculator was used to estimate the hourly output profiles for six different solar system orientations. The solar output was then used to estimate avoided costs and benefits for 11 components, which combined make up the grid value or societal value of the resource. Locational value and economic benefits are important components of the value of distributed resources like solar but were beyond the scope of this analysis. For each system orientation, a 25-year levelised avoided costs or benefits, in 2014 dollars, was established for the above components. The overall grid and societal values are the sum total of each of the components.

While the Vermont model considered 11 components, Austin Energy accounted for the following six benefits when considering the value of distributed solar:

- Avoided fuel costs, which is valued at the marginal costs of the displaced energy;
- Avoided capital cost of installing new power generation due to the added capacity of the solar system;
- Avoided T&D expenses;
- Line loss savings;
- Fuel price hedge value; and
- Environmental benefits

The largest benefits in Austin Energy's VOST is the value of energy component. Austin Energy's approach of valuing the energy supplied by a solar system is perhaps unique to Texas. In its algorithm, the energy value equals solar output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and operations and maintenance (O&M) costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine). Austin Energy assigns an environmental value based on the solar output times the REC price—the incremental cost of offsetting a unit of conventional generation. It has also included in a value for the fact that solar generation has no fuel price uncertainty.

This value is calculated by determining how much it would cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. The outcomes of each jurisdiction's analysis will depend on a combination of the local politics, existing regulatory framework, and DER company activity in each region. New York is an example of another region that is moving quickly to lay out a new framework, as described below.

### *6.4.4 NY REV LMP+D*

On December 23, 2015, the New York Public Service Commission (PSC) issued its *Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering.* The Notice posed a number of questions related to the development of interim and full-value methodologies of DER compensation that could be used as a successor to net energy metering. The initial concept put forth by the PSC was called LMP+D, meaning the Locational Marginal Price (wholesale market price) plus the value of avoided utility distribution investments. Figuring out the value of D is the crux of the proceeding, along with timing issues and concerns between various resource types and sizes.

In response, a group of the investor-owned utilities in New York and the solar companies (SolarCity, SunPower, and SunEdison) submitted a joint proposal on a gradual transition from current retail rate net metering to a new value of energy exports from DER based on LMP+D+E (externalities). New York State currently has three varieties of net metering for onsite (BTM) DER, remote facilities, and community DG

installations. This proposal focused on a transition for the latter two, but also laid out a general framework for the transition of future BTM resources starting on January 1, 2020. The proposal was written from the perspective of applying to all net metering resources generally, though the solar companies noted that that they remain silent on whether the comments should apply to non-solar technologies.

While community solar would begin to transition toward LMP+D+E, the proposal left intact retail rate net metering from the customer perspective. A new financial relationship would be established between the community solar developer and the utility, where the developer pays a fee in the amount of the difference between the sum of all credits applied to a customer bill (LMP+D+E, and during the transition, a transitional gap credit) and the full customer retail rate. The transition from retail rates to LMP+D+E would take place in a series of tranches of megawatts of community solar installations, where each tranche provides a set value of transitional gap credit (which is added on top of LMP+D+E on the customer bill) over a set period of time (from 15 to 25 years).

The proposal looks to begin transitioning from retail net metering for onsite, BTM resources beginning January 1, 2020, unless bill impacts and accelerating solar deployment trigger an earlier transition on a utility-specific basis. New DG customers would enter into a level of compensation for net exports (retail rates remain for consumption and self-supply) and maintain that compensation level for a period to be specified by the commission (approximately 15 to 25 years).

This proceeding will continue over several months until a consensus among stakeholders is reached.

# 7. KEY PLAYERS AND JURISDICTIONS TO WATCH

There are certain market players on the vendor and utility side, both globally and in Ontario, that deserve attention as the DER market develops.

## 7.1 Equipment Manufacturers and Integrators

The DER value chain begins with the vendors that make and distribute the various technologies.

### *7.1.1 ecobee*

Founded in 2007, Toronto-based start-up ecobee is a maker of smart thermostats and climate sensors. The company leverages a multi-channel sales approach, selling thermostats direct to consumers, via storefront and online retail, utility programs, and HVAC installers. Its flagship smart thermostat, the Smart Si is one of few smart thermostats certified with the OpenADR 2.b specification, and it has been deployed by utilities such as San Diego Gas & Electric, Pacific Gas and Electric, and National Grid.

ecobee's product line consists of the ecobee3, remote sensors for multi-room environments, and the Smart Si thermostat. ecobee3 competes with the Nest and Honeywell Lyric thermostat, and has received some of the strongest customer reviews of the three products. Smart Si integrates ZigBee SEP, so the device can communicate with a home's smart meter, providing up-to-date power consumption information that will help customers make more informed choices about home energy usage. That model was also part of SMUD's Communicating Thermostat Usability Study, published in July 2013, and received strong rankings for ease of use and overall preference. In addition, the thermostat received among the highest scores for actual ease of use, where the participants were measured in both the time it took them to perform a specific task on the thermostat and whether they were able to complete the task correctly.

### *7.1.2 SolarCity*

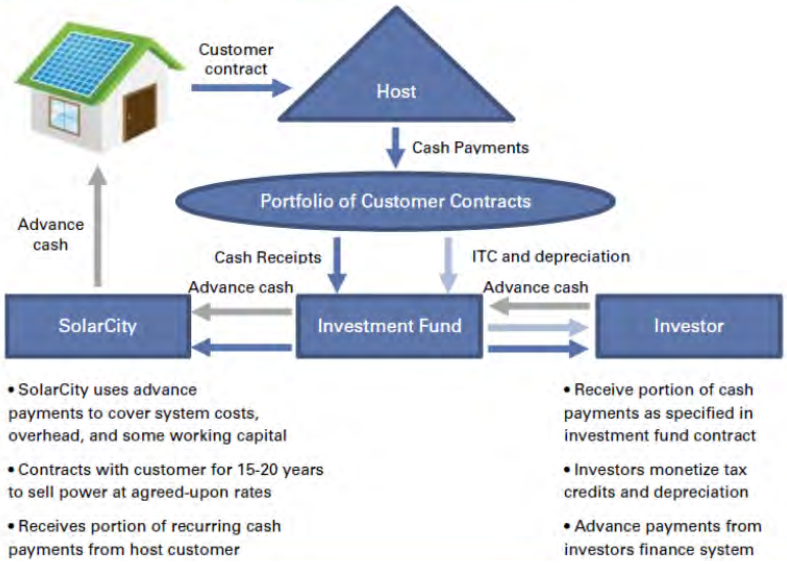
SolarCity's business model is focused on places where solar generation is a viable alternative to retail electricity rates. Its value proposition to energy consumers is a competitive price versus utility rates and long-term price certainty—prices follow a previously set escalation rate. The company's rates usually offer its customers a discount of between 10 15 percent compared to residential retail rates. Its customers also value other perceived benefits of SolarCity's offering, such as energy self-reliance and its lower carbon footprint.

Another key aspect of its offering is the reduction in the upfront costs needed to install solar PV. While most of SolarCity's customers could get the same or better benefits by owning their own system, not many have the financial depth to buy the system outright. SolarCity is able to alleviate a major hurdle to solar adoption by eliminating all, or a majority, of the upfront capital cost of a solar system installation for the consumer.

SolarCity also offers an interesting proposition for its investors. By signing long-term (usually 20 years) contracts, it locks in a long-term predictable cash flow. SolarCity reduces the embedded risk of solar investment by aggregating a large and diverse customer base. This allows the company to reduce its funding costs—in its last green bond issuance, the company paid just above 4 percent for its bonds. Finally, SolarCity's short project cycles—the time it takes to raise capital, find customers, install the project, and securitize them (pooling several lease contracts together into a security that merits a buyer access to future cash flows)—allows it to recycle its capital several times a year, multiplying its return on

equity compared to a single investment. Using this strategy, the company can offer interesting internal rates of returns to its investors—11 percent before any debt is taken into account (unlevered).

**Figure 7-1. SolarCity Solar Lease Structure**




*Source: Goldman Sachs*

### *7.1.3 Tesla*

Tesla Motors is well-known as the world's largest exclusive manufacturer of battery electric vehicles. The Palo Alto, California-based company employs over 10,000 people and has made waves in the automotive industry. In order to drive down the costs of the Li-ion batteries that power its vehicles, Tesla Motors is currently constructing a massive Li-ion battery pack manufacturing facility outside of Reno, Nevada, called the Gigafactory.

Tesla recently announced its entrance into the residential and small commercial energy storage market with the unveiling of its Powerwall product, which will be manufactured at the new Gigafactory facility alongside automotive batteries. Tesla will also offer energy storage solutions at the industrial and utility scale with its Powerpack product, a 100 kWh energy storage building block.
Tesla's contribution to the market will not be based on technology—at least not at the battery cell level. Tesla's effect on the market is likely to reach far beyond hardware deployments. Specifically, that influence will come in building economies of scale, popularising the home storage concept with the general public, and, ultimately, developing viable financing schemes. Tesla's move will also certainly spawn imitators in the residential space, encouraging competition and differentiation in the marketplace. Tesla can bring its sales and installation machine to bear in a portion of the market plagued by fuzzy margins, fickle business cases, and inconsistent interconnection fees. In a similar fashion, SolarCity and its peers can change the residential solar market simply by deciding to establish a market offer in a particular territory.

### *7.1.4 Younicos*

Younicos, founded in 2006 by executives from German solar manufacturer Solon, is a privately held firm located in Berlin, Germany. The company employs 114 people, and has recently become active in the energy storage market. In April 2014, it acquired the assets of grid battery start-up Xtreme Power. In

January 2015, it was restructured into three main units: The Technology Business Unit, the Development Company Business Unit, and the Consulting Company Business Unit.

Younicos develops energy storage system management software and controls, including advanced weather forecasting, in order to maximize the performance and longevity of systems. The company is focused on effective integration between storage systems and grid communications networks. Its products are designed to be technology-agnostic and are able to integrate a variety of batteries, inverters, and balance of system components. Younicos has substantial experience integrating energy storage systems into grids with high penetrations of renewables, notably in Germany and on several islands, including Graciosa in the Portuguese Azores.

## 7.2 Solution Providers

Once the technologies are in place, it can take another actor to bring them together in a customer-friendly package and to provide the software to manage the resources.

### *7.2.1 Rodan Energy Solutions*

Rodan, which calls itself Canada's largest independent demand response and smart grid solutions provider, is a smart grid integrator mostly focused on energy management: metering, data management and demand response along with engineering services. The business began in 2002 as Canadian Metering Services, a very small meter-services firm. Today it uses a business model driven by a Canadian law that makes the largest power users interact directly with the ISOs. They are required to have a high voltage meter and to hire a metering services firm to install and help them manage the meter and do reporting to the ISO.

Rodan provides services to 60-plus utilities and ISOs in North America, close to 200 large C&I clients and works with many of North America's largest power producers. The firm has about 400 MW of demand response under management. Rodan was the first company to receive designation as a DR aggregator in Ontario and claims to be the largest aggregator in Canada.

In May 2016, Rodan was picked by the IESO as the province-wide demand response aggregation operator and dispatch administrator, to run its "Peak Saver Plus" demand response program, a direct load control program. As the incumbent aggregation operator, Rodan will continue to dispatch, support and manage about 320,000 load control devices at residential and small-commercial facilities.

### *7.2.2 ENBALA*

ENBALA Power Networks was founded in 2003 in Toronto. The company works with grid operators, utilities, and individual C&I customers to customise and implement DER protocols that respond to real-time information on grid conditions and pricing. Its utility smart grid network manages demand for C&I assets, then aggregates and markets this flexibility. Ideally, ENBALA wants to provide multiple types of services such as morning ramps, wind/solar integration, and deferring T&D upgrades.

ENBALA works with large C&I customers that have inherent energy storage capabilities in their processes through tools like thermal mass build up, chilled water loops, and water/wastewater capacity. These types of loads have a great deal of flexibility, and ENBALA looks to harvest this storage and aggregate loads to offer as a fast-responding resource to grid operators. The goal is to find the optimal amount of curtailable capacity from each facility that will not be intrusive on its operations instead of looking to do full shutdowns at sites.

Notably, ENBALA's offerings involve no hardware installed onsite aside from a local communications panel, as the existing BAS/SCADA solution is used for control purposes. ENBALA operates on its own servers in a secure location for security purposes. An optimisation engine sits between the servers and the customers. The engine is tied to 1-second communications with the loads and can make operational decisions every few seconds to change load levels.

## 7.3 Utilities

DER development does not exist strictly outside of the utility purview. There are utilities that proactively engage this transformation for the benefit of its operations and its customers.

### *7.3.1 PowerStream*

PowerStream is an Ontario energy company providing power and related services to 375,000 customers residing or owning a business in communities located immediately north of Toronto and in Central Ontario. It is jointly owned by the Cities of Barrie, Markham, and Vaughn. PowerStream is considered a leader in the province with respect to DER implementation. In March 2016, the utility launched its latest innovative project, the POWER.HOUSE pilot. The POWER.HOUSE is Canada's first virtual power plant and uses an aggregate fleet of 20 residential solar and energy storage systems located in customer's homes. Using intelligent software, the fleet can be controlled to simulate a single, large power generating facility. The technology used is both rooftop solar and BTM Li-ion battery storage at a customer's home.

## KEY CONSIDERATIONS

The transformation of the electric grid does not happen overnight. Aligning technology, policy, and capital drivers with suitable business models that are scalable beyond local jurisdictions is a major challenge that is taking place in hundreds of cities, states/provinces, and countries today.

There are considerable lessons learned that are applicable to industry and policymakers in Ontario and other jurisdictions alike. Ontario, like many other jurisdictions, has identified key system characteristics and abiding values that are consistent with the goal of regulators and indicative of the overarching approach for all stakeholders navigating the transition in the energy sector. While resources, local politics and policy objectives, and regulations are variable by geography, most utilities are committed to nurturing an energy system that is:

- Efficient and effective with a high degree of reliability at a principle-based cost;
- Appropriately leavened with competition-based pricing for as many system attributes and assets as can be reasonably accommodated;
- Low carbon; and
- Capable of serving all of its customers and meeting their increasing expectations with a reasonable return expectation for utilities.

With a growing number of case studies, successes, and failures to review, the following key considerations are an attempt to summarise some of the most important findings, risks, and opportunities for the future of electricity supply.

***It is not necessarily centralised versus distributed generation.***

Centralised power generation remains a critical element for the electric grid and an enabler that will allow distributed energy resources to flourish. The question is how, within each jurisdiction, centralised and distributed resources can successfully integrate and add value to the overall electricity grid from a resilience, safety, and efficiency perspective as well as from a cost perspective. While some utilities had generally resisted these technologies, most utilities today are actively adapting to the changing business environment. In the face of flat load growth, utilities need to generate new sources of revenue to satisfy shareholders or stakeholders.

At the centre of this transition is investment in distributed energy resources that is both a response to policy mandates targeted at environmental goals and a means to update the business model. As the owner/operators of the grid, utilities are well positioned to maximise the value of distributed energy resources to the electric grid. In parallel, regulatory frameworks will need to evolve so that utilities are rewarded for innovation and able to earn a reasonable return.

The bigger dichotomy that requires attention as the prevalence of distributed energy resources increase is between the wholesale and retail electricity markets. Distributed energy resource growth on the retail level can inadvertently affect wholesale market dynamics and vice versa. Explicit cooperation between the grid operators at each level is required for proper integration. The New York Reforming the Energy Vision proceeding has made collaboration between the New York Independent System Operator and the utilities a key factor from the beginning. California has introduced the concept of bifurcation whereby distributed energy resources that can provide grid services would participate in the California Independent System Operator markets, while those that respond to prices and dynamic rate structures would participate on the retail side. Such alignment will not happen by chance, but only through deliberate planning.

***Policy remains the leading driver, but economics is quickly catching up.***

It was policy that kick started many of the markets for distributed energy resources. Renewable energy deployment targets, emissions reduction targets, DG deployment targets, tax credits, FITs, net metering, and emissions regulations were the precursors to the transformation of the electricity system now underway.

Successful long-term policy is achieved when markets become self-sufficient, and there is suitable progress being made toward a jurisdiction's shared goals and values. This underscores the relevance of local politics—even at the city and state/province level in the absence of federal leadership. Local activity has regularly set the stage for broader federal implementation, so grassroots efforts can be just as effective, if not more so, than top-down approaches.

While policy kick-started the trend towards distributed energy resources, economics is accelerating it. The cost of most distributed energy resources is on the decline, which in its own right is fuelling additional interest from customers. At the same time, end uses are becoming more efficient (e.g., heating and cooling, lighting, industrial processes, etc.). As customers use less electricity to achieve the same output, and alternatives to grid supplied electricity become less expenses, there will be additional upward pressure on the cost of grid-supplied electricity.

***Cost-effectiveness is still the major success framework.***

Cost-effectiveness is the leading characteristic by which utilities, regulators, and customers will ultimately judge changes to the energy system. However, cost-effectiveness depends on a wide variety of considerations. These include: defining cost-effectiveness for *whom* and over what period of time (near-term vs. long-term savings); what is a suitable rate of return; how to value non-energy benefits and externalities; how to compensate utilities for the role they play in maintaining reliability or advancing policy; how quickly certain changes should be enacted; and how to simultaneously enable innovative companies to flourish while not shifting costs in a way that does not abide by a region's stated values. In this regard, fuel price risk is emerging as a significant factor, as natural gas increasingly displaces coal for baseload applications in North America, in particular. Wind and solar PV are the lowest-cost options for electricity in a growing number of markets—but are not dispatchable. What is the value for a technology to provide steady predictable costs for 20-30 years? How can utilities maximise the locational value and manage DER? The appropriate quantification of such benefits will speed the transition and attract resources where they are most needed on the grid.

***Regardless of ownership, utility-vendor relationships matter.***

DER is commonly viewed as the domain of innovative, high-tech companies offering new consumer-focused products and services, but DER at scale is forcing utilities to be more proactive. DER ownership by utilities is a key issue that must be addressed as part of the process. In some markets where competition is highly valued, utility DER ownership will be prohibited or limited to specific cases. NY REV has concluded that utilities can only own DER in specific cases after market-based solutions have been attempted but have not returned cost-effective proposals. Other jurisdictions will be more liberal with utility DER ownership, particularly in vertically integrated territories. There is no one right answer; it is just important to assure that the issue gets vetted in a public, transparent manner where all concerned parties have a chance to assert their viewpoints.

Regardless of whether it is a vertically integrated or unbundled utility, partnerships are of increasing importance. Utilities must experiment with both owning and operating power resources where allowed (central station and distributed) as they have historically while also leveraging specialisation through third-party vendors that can help them integrate the growing penetration of DER technologies onto the gird.

Coordination with and learning from innovative new business models is now directly linked to a utility's financial future and the realisation of societal goals.

***There are implications for each decision made.***

There is not a straight path to achieve stated goals for the energy system. Even in cases where there is broad political support to meet ambitious targets—often related to carbon reduction targets, renewable energy deployment, or market restructuring/liberalisation—there are both intended and unintended consequences.

In the case of Germany, for example, carbon emissions have reached their highest levels in the country despite some of the highest penetration of wind and solar in the world. Simultaneously, shutting down nuclear power has resulted in an increase in coal use that has more than offset the gains made by a shift to renewables. Feed-in tariffs in Spain, Japan, Czech Republic, Germany, the United Kingdom, and elsewhere have led to boom and bust markets for solar.

In the United States, Independent System Operator-New England announced that 2015 annual system emissions increased over 2014, the first such occurrence in several years. The main culprit is the closure of the Vermont Yankee nuclear plant, which was replaced by natural gas generation. With more nuclear retirements on the horizon, policymakers concerned with carbon emissions must deliberate on the best path for the whole grid and not just in silos of renewable technologies.

Similarly, deregulation and unbundling do not automatically result in lower costs for consumers. In the United States, for example, it is not clear if retail rates are lower in states that have restructured markets compared to those that are vertically integrated—depending on how it is measured. While competition may lead to market efficiencies, lost in a pure wires utility are opportunities to leverage the entire energy value chain from generation to transmission to retail delivery. Demand response could be used to defer investments in new system capacity, while distributed resources over time may make up a modern version of a resource portfolio. The utilities may benefit by diversifying their rate bases in line with policy objectives at a cost that is affordable for customers, although their incentives to do so must be aligned as well.

# Mowat Centre

ONTARIO'S VOICE ON PUBLIC POLICY

The Mowat Centre is an independent public policy think tank located at the School of Public Policy & Governance at the University of Toronto. The Mowat Centre is Ontario's non-partisan, evidence-based voice on public policy. It undertakes collaborative applied policy research, proposes innovative research-driven recommendations, and engages in public dialogue on Canada's most important national issues.

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